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CREDIT OPINION

22 February 2018

Update

Rate this Research

RATINGS

ALLETE, Inc.

Domicile	United States
Long Term Rating	A3
Type	LT Issuer Rating
Outlook	Negative

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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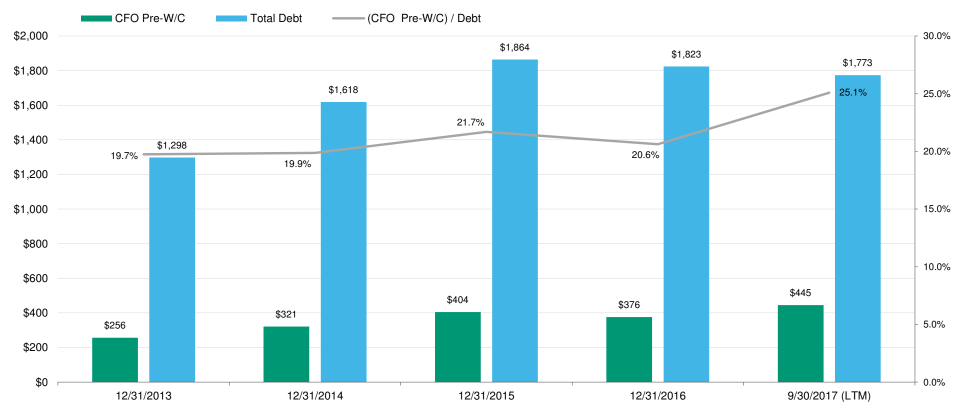
ALLETE, INC.

Update following negative outlook

Summary

ALLETE's credit is underpinned by the largely stable and predictable cash flows associated with its regulated assets that account for 80% of consolidated net income, and the generally credit supportive nature of the rate making mechanisms available to its regulated companies. The company's credit also reflects our expectation that ALLETE's unregulated business will remain relatively small and will also produce stable cash flows. ALLETE's credit quality is tempered by the company's material exposure to commodity risk-exposed industrial customers.

Exhibit 1 1
Historical CFO Pre-W/C, Total Debt and CFO Pre-W/C to Debt ($MM)



Source: Moody's Financial Metrics™

Credit strengths

» Access to credit supportive ratemaking construct

» Plan to maintain cost competitive position while transforming generation mix

Credit challenges

» Credit negative rate case outcome

» Deteriorating financial ratios

» Material exposure to industrial customers and exposure to unregulated business creates potential for cash flow volatility

Rating outlook

ALLETE's negative outlook reflects the lower financial ratios we expect the company to produce resulting from the combined effect of a credit negative rate case outcome and lower cash flows due to tax reform. We forecast the company's CFO pre-working capital to debt will fall to roughly 19.5%, below its existing downgrade threshold of 22%, on a sustained basis.

Factors that could lead to an upgrade

» Although unlikely given the company's negative outlook, ALLETE's rating could be raised if the company achieves stronger than expected financial ratios such that it reports CFO pre-WC to debt and RCF to debt above 24% and 19%, respectively, on a sustained basis.

Factors that could lead to a downgrade

» ALLETE could be downgraded if it continues to experience a decline in the credit supportiveness of the Minnesota regulatory framework. The company could also be downgraded if it saw a substantial deterioration in economic conditions that resulted in a material and sustained drop in retail electricity volumes not offset by off-system sales or other means. A downgrade could also result from a weakening of ALLETE's financial ratios, such that CFO pre-WC to debt remains below 22%. A material increase in ALLETE's unregulated business segment and/or marked increase in the business risk profile of the company's unregulated segment could place downward pressure on the company's rating as well.

Key indicators

Exhibit 2
ALLETE, Inc. Indicators

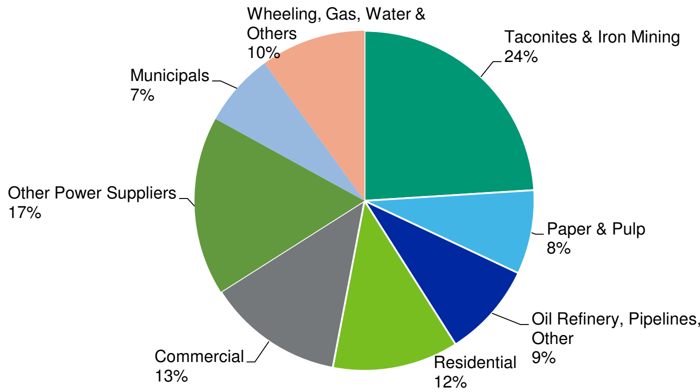
US Millions	Dec-13	Dec-14	Dec-15	Dec-16	LTM Sep-17
CFO pre-WC + Interest / Interest	5.3x	6.2x	6.5x	5.8x	6.8x
CFO pre-WC / Debt	19.7%	19.9%	21.7%	20.6%	25.1%
CFO pre-WC – Dividends / Debt	13.9%	14.7%	16.4%	15.0%	19.0%
Debt / Capitalization	41.6%	43.3%	43.8%	42.5%	40.3%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Profile

ALLETE Inc. (ALLETE, A3 negative) is a Duluth, MN based energy company. Its regulated operations represent about 75% of consolidated operating revenue and consist of its operating utility division Minnesota Power (MP, not rated, rate base $2.6 billion), a wholly-owned regulated utility subsidiary Superior Water Light & Power (SWL&P, A3 negative, rate base $67 million), and an 8% ownership stake in American Transmission Company LLC (ATC, A2 stable). MP provides integrated electric services to around 145,000 retail customers. It also provides wholesale services to 16 municipalities in northeastern Minnesota and its Wisconsin based, sister utility company SWL&P. MP is heavily exposed to industrial customers, with 50% of its energy output being sold to industrial end-users in 2017. SWL&P is a small transmission and distribution utility company serving about 15,000 electric, 13,000 natural gas and 10,000 water customers in northwestern Wisconsin.

Exhibit 3
2016 Regulated Operations Revenue



Source: Company Data

ALLETE's unregulated segment consists of contracted coal mining operations in North Dakota, development and ownership of unregulated energy projects, U.S. Water, Services (not rated), an industrial water treatment company, and a small real estate investment segment.

Detailed credit considerations

CREDIT NEGATIVE GENERAL RATE CASE OUTCOME PARTIALLY OFFSETS SUPPORTIVE RATEMAKING MECHANISMS

ALLETE's credit is largely driven by the credit quality of its regulated vertically integrated utility business Minnesota Power (MP, not rated), that accounts for roughly 80% of consolidated cash flows.

MP is a Minnesota-based utility whose operations have access to above average ratemaking mechanisms including the application of a forward test year when setting rates, the ability to implement interim rates soon after filing for a general rate case, and access to multiple rider mechanisms. However, these credit positive ratemaking tools are mitigated by MP's latest general rate case outcome that points to a less constructive regulatory relationship between MP and the Minnesota Public Utilities Commission (MPUC).

On 30 January 2018, the Minnesota Public Utilities Commission (MPUC), MP's primary regulator, approved a $12.6 million rate increase for MP, 14 months after the company had filed its first general rate case since 2011. The MPUC's approved rate increase is materially lower than MP's original request of $55 million (subsequently revised to $39 million when a key industrial customer restarted operations). It is also significantly below the interim rate increase of $35 million that MP began collecting from customers in January 2017 (revised to $32 million as of 1 May 2017). The rate case outcome is credit negative for ALLETE because MP, will see a net reduction in customer rates versus the anticipated 6% net increase. This will place downward pressure on the company's financial metrics, reducing CFO pre-working capital to debt to the low 20% range before taking into account any potential future negative cash flow impact relating to federal tax reform.

The difference between MP's $39 million request and the MPUC's $12.6 million order is driven by both a lower approved equity return as well as expense disallowances. The MPUC lowered MP's allowed ROE to 9.25% from the requested 10.25%, below the national average of about 9.6% for 2017. The lower ROE represents about $20 million of the difference between MP's ask and the approved rate increase. The remaining difference relates to various expense disallowances including a decision to disallow the recovery of about $3 million of prepaid pension expenses. Although the amount is relatively small, it is noteworthy because Northern States Power Minnesota (A3 stable), the state's largest regulated utility, has received approval to recover such expenses in its rates. MP's inability to recovery certain expenses already incurred will make it difficult for it to earn its below average allowed equity return without reducing costs elsewhere.

Another credit negative development resulting from MP's general rate case was the MPUC's ruling against the adoption of an annual rate review mechanism (ARRM) which was intended to mitigate the impact of MP's industrial customers idling their plants. Unlike peer utilities in the state with more balanced mix of customers, MP's industrial customers account for about half of its annual sales volume, and their vulnerability to broader economic cycles makes them inherently more volatile than residential customers. The ARRM would have provided an automatic ROE true-up that would have allowed MP to add a surcharge on customer bills if its earned ROE fell below a predetermined level or provide a refund if it was higher. The decision to deny a rate true-up mechanism differs from the treatment of other utilities in the state that have access to similar types of mechanisms.

WEAKENING FINANCIAL RATIOS

While ALLETE's historical credit metrics were robust, the higher indebtedness incurred to fund a portion of its extensive capex program during the first half of the decade had reduced its debt coverage ratio to around 18% from the 24% achieved in 2010 and 2011. We believe that ALLETE's heavy exposure to industrial load and the demand volatility associated therewith requires it to generate run-rate debt coverage metrics closer to the mid-20% range.

ALLETE completed its sizeable environmental investments in 2015 and has since stepped down its capex budget to $200-300 million per year (roughly half the capex levels seen in 2014). Prior to the passage of tax reform and the MPUC's decision on MP's 2016 general rate case, these reduced investment levels, the addition of recently completed capex to rate base, and the decision to target a dividend payout ratio of 60-65%, were expected to yield improved financial ratios, including achieving CFO pre-WC to debt and retained cash flow to debt ratios above 22% and 17%, respectively.

However, the combined impact of MP's negative rate case outcome as well as the lower cash flows resulting from the reduced tax collection in customer rates and deferred tax liability refunds will place downward pressure on ALLETE's financial ratios. We now forecast CFO pre-WC to debt falling below 20% on a sustained basis, below the 22% downgrade threshold set for ALLETE, barring any mitigating responses by the company.

MATERIAL INDUSTRIAL CUSTOMER EXPOSURE ADDS VOLATILITY TO THE COMPANY'S BUSINESS RISK PROFILE

ALLETE's exposure to industrial customers is significant, representing roughly 50% of annual sales volume in most years, the highest within the Moody's US regulated utility universe. The make-up of its industrial customers consist of operating margin sensitive businesses such as iron pellet and taconite producers (67% of industrial KWh sold in 2017), paper, pulp and wood products companies (15%), and oil pipelines and other industrials (18%). All three industries faced challenging market environments that translated into weaker industrial sales in 2015 and 2016, but the trend reversed in 2017 with industrial customers returning to full production for most of the year.

The cyclicality of ALLETE's industrial customers' demand is a credit negative since these are the company's largest customers. In the absence of decoupling mechanisms, lower than anticipated regulated volumes can have a material negative impact on ALLETE's cash flow from operations. This was particularly apparent in 2009 when its taconite producer customers operated at 45% of capacity (procuring only 2.1 GWh of power). The impact on 2015 and 2016 operating cash flows is less obvious due to one time events such as the fee received for building a wind farm for a third party investor owned utility and increased off-system sales volumes.

ALLETE looked to mitigate the risk posed by lower industrial customer sales when it filed for the subsequently denied ARRM mechanism.

Still, going forward ALLETE will be able to offset some of the cash flow volatility associated with its industrial customers through the application of the legislatively approved Energy-Intensive Trade-Exposed (EITE) Customer Rates. Those are intended to be revenue neutral however they shift some of MP's fixed cost recovery away from industrial customers to the more stable residential and commercial customers. The Minnesota's EITE customer ratemaking legislation was enacted in 2015, with the intent of providing competitive rates for certain industries such as mining and forest products.

PLAN TO MAINTAIN ITS COMPETITIVE COST POSITION

MP's material exposure to industrial customers that are particularly margin sensitive means it must maintain rates as low as possible in order for these customers to operate and avoid the risk of customer self-generation. The majority of its power requirements are currently generated through its coal-fired facilities (41% of 2017 MWh) and renewable power plants (17%). The balance of its energy needs are procured in MISO and other power suppliers (26%) and long-term power purchase agreements (PPAs) (16%).

ALLETE aims to maintain MP's cost competitive position in the future by reshaping its power supply from a predominantly coal-based energy mix to one where renewables, coal-fired and natural gas power each contribute about one third of the expected load requirement by 2025.

Following the completion of the Bison 4 wind farm in late 2014, MP owns 522 MW of highly economical wind capacity (average cost of less than 3ct/KWh for its North Dakota 497 MW Bison Wind Energy Center), and maintains two long-term PPAs totaling 98MW. MP intends on increasing its access to renewables over time through two additional long-term PPAs with Manitoba Hydro for a total capacity of 383 MW set to start in 2020.

MP is also making progress with the transformation of its coal generation fleet. The company completed the required environmental upgrades at its Boswell Unit 4 (468 MW) in 2015, and idled its two Taconite Harbor units (150 MW) in September 2016 with plans to retire both in 2020. Finally, MP announced its intention to retire its Boswell Units 1 and 2 coal plants (135 MW) in 2018. The company does not expect to record any impairment charges as a result of their early retirements.

MP's exposure to natural gas fired generation currently only consists of 110 MW of capacity. However, the company plans on adding to its natural gas fired capacity post-2020 with the construction of a new 525-550 MW plant. MP will purchase approximately 50% of the output.

Although the fuel mix diversification is a credit positive, the need to maintain access to reliable cost competitive energy to retain its industrial customer base will require some coal generation to continue and will leave the company exposed to potentially costly environmental laws and regulations that will likely require further plant retrofits.

ALLETE'S RELATIVELY SMALL UNREGULATED BUSINESS ADDS A MODICUM OF RISK

ALLETE's unregulated business primarily consists of ALLETE Clean Energy (ACE, not rated) and US Water Services (US Water, not rated).

ALLETE has rapidly grown its portfolio of contracted renewable assets over the past four years. ACE has acquired six wind farms and currently owns 535 MW of wind assets across multiple states. Going forward we expect the pace of growth to subside some. Although these assets are fully contracted with investment grade offtakers, the stability of their cash flow generation is tied to fluctuating wind production and power purchase agreements (PPAs) that begin to expire in 2018. The re-contracting risk the PPAs carry creates uncertainty about the future cash flow generation potential of these assets.

ALLETE's ownership of US Water Services not only increased the company's exposure to unregulated, and inherently more volatile, businesses, but also marks a departure from the fully contracted renewable assets it has been adding to the segment. Nevertheless, with total assets of $292 million, US Water remains a small investment relative to ALLETE's consolidated assets of $5.1 billion as of 31 December 2017.

Overall, ALLETE's rating assumes that the company's unregulated segment will remain modest relative to the consolidated group, and its business risk profile will not jeopardize the overall stability and predictability of the company's operating cash flows.

Liquidity analysis

ALLETE's liquidity is adequate. As of 31 December 2017, the company had $99 million in cash on its balance sheet and $388 million available under its $400 million, 5-year revolving bank facility set to expire in October 2020. Borrowings under the bank facility are not subject to a material adverse change clause; however, there is a cross-default clause to other indebtedness (>$35 million). The sole financial covenant in ALLETE's revolving credit facility is a maximum funded debt to total capital covenant of 65%. As of 31 December 2017, ALLETE's debt/cap ratio was approximately 42%.

ALLETE's debt maturity profile is manageable. The company has $50 million of first mortgage bonds due in April 2018.

As of 31 December 2017, the company generated $403 million in operating cash flows, invested $208 million in capital investments, and distributed $109 million in dividends to its shareholders, resulting in a positive free cash flow position of $86 million that the company used to pay down debt. Going forward, we expect the company to become marginally free cash flow negative given its lower than anticipated utility rates, a temporary increase in capital expenditures to fund the Great Northern Transmission line, and the company's stated target dividend payout ratio of 60-65%. We expect the company will fund this cash shortfall through a mix of cash on hand and short-term debt.

Rating methodology and scorecard factors

Exhibit 4

Rating Factors				
ALLETE, Inc.				
Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 9/30/2017		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	Baa	Baa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Ba	Ba	Ba	Ba
b) Generation and Fuel Diversity	B	B	B	B
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.3x	Aa	6x - 6.5x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	22.2%	A	18% -20%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	16.6%	Baa	13% - 15%	Baa
d) Debt / Capitalization (3 Year Avg)	42.0%	A	40% -45%	Baa
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		Baa1
HoldCo Structural Subordination Notching	0	0	0	0
a) Indicated Rating from Grid		A3		Baa1
b) Actual Rating Assigned		A3		A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/2017(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics™

Ratings

Exhibit 5

Category	Moody's Rating
ALLETE, INC.	
Outlook	Negative
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Secured	A1
Bkd LT IRB/PC	A3
SUPERIOR WATER, LIGHT AND POWER COMPANY	
Outlook	Negative
Issuer Rating	A3
Senior Secured	A1

Source: Moody's Investors Service

Appendix

Exhibit 6

Peer Comparison [1]

	ALLETE, Inc. A3 Negative			Otter Tail Corporation Baa2 Stable			Northern States Power Company (Minnesota) (P)A2 Stable			Interstate Power and Light Company Baa1 Stable		
(in US millions)	FYE Dec-15	FYE Dec-16	LTM Sep-17	FYE Dec-15	FYE Dec-16	LTM Sep-17	FYE Dec-15	FYE Dec-16	LTM Sep-17	FYE Dec-15	FYE Dec-16	LTM Sep-17
Revenue	1,486	1,340	1,423	780	804	839	4,757	4,900	5,060	1,775	1,820	1,833
CFO Pre-W/C	404	376	445	147	163	177	1,303	1,369	1,343	391	341	381
Total Debt	1,864	1,823	1,773	706	706	734	5,150	5,370	5,407	2,119	2,445	2,574
(CFO Pre-W/C + Interest) / Interest Ex	6.5x	5.8x	6.8x	5.0x	5.7x	6.7x	6.8x	6.7x	6.5x	4.7x	4.0x	3.9x
(CFO Pre-W/C) / Debt	21.7%	20.6%	25.1%	20.8%	23.0%	24.1%	25.3%	25.5%	24.8%	18.4%	13.9%	14.8%
(CFO Pre-W/C - Dividends) / Debt	16.4%	15.0%	19.0%	14.2%	16.2%	17.3%	20.3%	18.1%	15.4%	12.1%	7.9%	9.0%
Debt / Book Capitalization	43.8%	42.5%	40.3%	46.6%	44.1%	44.0%	40.3%	40.0%	39.4%	38.1%	39.1%	38.4%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade

*Source: Moody's Financial Metrics*TM

Exhibit 7

Cash Flow and Credit Measures [1]

CF Metrics	2013	2014	2015	2016	2017
As Adjusted					
EBITDA	**327**	**374**	**459**	**456**	**498**
FFO	**263**	**340**	**407**	**382**	**435**
- Div	75	84	98	103	107
RCF	**188**	**256**	**309**	**279**	**328**
FFO	263	340	407	382	435
+/- ΔWC	3	(9)	(32)	(6)	(5)
+/- Other	(7)	(19)	(3)	(6)	10
CFO	**259**	**313**	**373**	**370**	**440**
- Div	75	84	98	103	107
- Capex	340	585	302	280	291
FCF	**(156)**	**(357)**	**(27)**	**(13)**	**42**
Debt / EBITDA	4.0x	4.3x	4.1x	4.0x	3.6x
EBITDA / Interest	5.5x	6.1x	6.3x	5.8x	6.5x
FFO / Debt	20.3%	21.0%	21.9%	20.9%	24.5%
RCF / Debt	14.5%	15.8%	16.6%	15.3%	18.5%

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months.

*Source: Moody's Financial Metrics*TM

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CREDIT OPINION
14 July 2017

Update

Rate this Research

RATINGS

Alliant Energy Corporation

Domicile	Madison, Wisconsin, United States
Long Term Rating	Baa1
Type	LT Issuer Rating - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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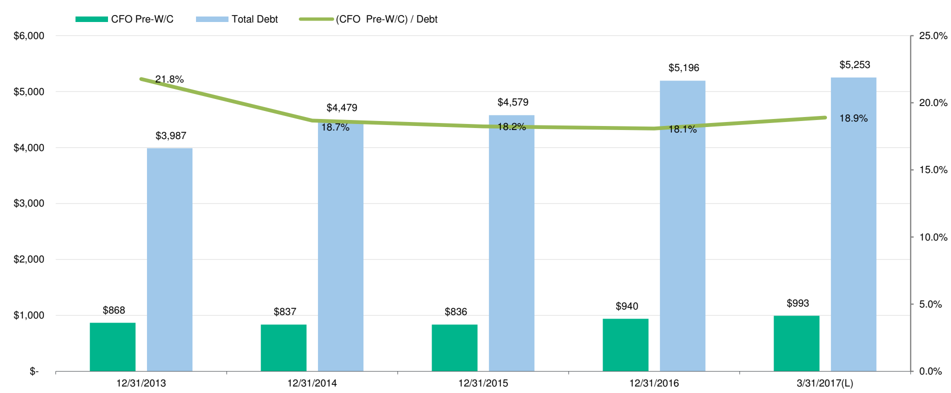
Alliant Energy Corporation

A Regulated Electric and Gas Utility Holding Company

Summary Rating Rationale

Alliant Energy Corporation's (Alliant) Baa1 Issuer Rating reflects the credit supportive regulatory environments in which its utilities operate and the predominantly rate regulated nature of the company's business activities. The rating also considers the execution risk associated with its utilities sizeable capital expenditure program, as well as the structural subordination of parent level debt holders relative to the subsidiaries' existing debt.

Exhibit 1
CFO Pre-W/C, Total Debt and CFO Pre-W/C to Debt
($MM)



Source: Moody's Financial Metrics

Credit Strengths

» Utilities operate in constructive and credit supportive regulatory environments

» Stable credit metrics that are in line with credit rating

» Material operations in two states and FERC exposure provides some regulatory diversity

Credit Challenges

» Sizeable capital investment program underway at both utilities

» Industrial exposure can lead to cash flow volatility

Rating Outlook

Alliant's stable outlook incorporates our expectation that its utility subsidiaries will continue to receive credit supportive regulatory treatment and maintain financial metrics in line with utility holding companies in the high Baa range. It also reflects the stable outlook on its two utility subsidiaries.

Factors that Could Lead to an Upgrade

» Alliant's rating could be upgraded if there is a significant improvement in its financial metrics such that the ratio of cash flow from operations before changes in working capital (CFO pre-WC) to debt were to reach the low-20% range, on a sustained basis. An upgrade could also be triggered by an upgrade of one or both of its utility subsidiaries.

Factors that Could Lead to a Downgrade

» Alliant's rating could be downgraded if there is a sustained deterioration in its debt coverage metrics such that CFO pre-WC to debt fell to the mid-teens. A downgrade could also be triggered at Alliant if one or more of its utilities were to be downgraded. An increase in holding company debt could place downward pressure on the rating as well.

Key Indicators

Exhibit 2

KEY INDICATORS [1]
Alliant Energy Corporation

	12/31/2013	12/31/2014	12/31/2015	12/31/2016	3/31/2017(L)
CFO pre-WC + Interest / Interest	6.1x	5.8x	5.5x	6.4x	6.6x
CFO pre-WC / Debt	21.8%	18.7%	18.2%	18.1%	18.9%
CFO pre-WC – Dividends / Debt	16.5%	13.9%	13.1%	13.2%	13.9%
Debt / Capitalization	42.5%	43.8%	43.0%	44.9%	44.7%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Detailed Rating Considerations

SIZEABLE CAPITAL INVESTMENT PROGRAM UNDERWAY AT BOTH UTILITY SUBSIDIARIES

Alliant continues to implement its decade-long capital expenditure plan that seeks to grow and transform its generation fleet away from a heavily coal dependent mix to a more balanced and environmentally compliant portfolio by 2024. Based on its latest forecast, the company plans on investing $5.6 billion between 2017 and 2020, up from $3.9 billion invested from 2013 to 2016, or about 3x depreciation.

Driving Alliant's capex plan are new generation investments, accounting for about 35% of planned investments. The company placed its first of two large gas fired generators into service in April 2017 and has begun construction on the second plant with an in-service date scheduled by early 2020. In addition, the company has also announced plans to add up to 1,100 MW of wind generation capacity to its portfolio by 2020, with 500 MW already approved by its state regulators. The balance of Alliant's investments target maintenance capital investments, some environmental projects at its remaining coal fired power plants, and electric and gas distribution.

Large environmental and new generation capital projects at Alliant's utilities are pre-approved by their relevant state regulators, and benefit from "advanced ratemaking" in Iowa. As a result, we view any disallowance risk as minor, and Alliant's rating assumes that the utilities will be able to fully recover their planned investment via rates when the plants are placed in service and added to rate base. Nonetheless, we recognize that material generation investments, particularly Alliant's gas fired power plants, carry greater execution risk and place added strain on the company's financial position given the amount of capital deployed, the time it takes to build these assets, and the complexity of bringing these projects online.

ABOVE AVERAGE CREDIT SUPPORTIVE REGULATORY ENVIRONMENTS

We view the credit supportiveness of the Wisconsin and Iowa regulatory jurisdictions as strong relative to other state regulatory environments. Each yields consistent and predictable rate case outcomes that allow the utilities to generate returns that are in line with or above those granted to their peers. Additionally, Alliant's exposure to the FERC's regulatory construct through the wholesale operations at its utilities (accounting for 9% of 2016 revenues) and its 16% stake in the American Transmission Company (ATC, A2 stable, 9% of pre-tax income) is highly credit supportive. The FERC offers formula based ratemaking with monthly fuel and annual return true-ups under an above-average allowed equity return even after adjusting for the downward revision in ATC's base ROE to 10.32% (excluding incentive adders) following a September 2016 FERC order.

Slightly less credit supportive are the historical test years used when setting retail rates in Iowa, and Wisconsin's less automatic cost recovery mechanisms, as well as the inability to earn a cash return while plants are under construction. These regulatory features add lag in cost recovery and dampen credit metrics, particularly at a time of elevated capital investments.

CREDIT METRICS IN LINE WITH RATING

Alliant's aggressive capital investment plan has placed downward pressure on the company's historically strong financial metrics. Alliant has seen its CFO pre-W/C to debt ratio decline to the high teens from the low twenty percent range due to increased leverage used to partially finance its extensive capital investment program, as well as lag in cash flow recovery of capital investments. As of 31 March 2017, interest coverage and CFO pre-W/C to debt were 6.6x and 18.9%, respectively. These ratios map to the company's Baa1 Issuer Rating under the regulated electric and gas utility methodology and are comparable to ratios generated by similarly rated utility holding company peers.

Going forward, we expect Alliant's credit metrics to remain near their current levels as the company continues to target a debt to capitalization ratios of about 40% by issuing a mix of debt and equity to fund its multi-billion dollar capital investment program, as well as its plan to dividend 60-70% of net income to its public shareholders.

SIGNIFICANT INDUSTRIAL EXPOSURE MITIGATES BENEFIT OF REGULATORY DIVERSIFICATION

Alliant benefits from geographical and regulatory diversity through its material electric and natural gas operations in both Wisconsin and Iowa, as well as exposure to FERC through its wholesale segment and investment in ATC. Mitigating some of these benefits are the utilities significant exposure to industrial customers. In the absence of a decoupling mechanism, this leaves both utilities more vulnerable to economic downturns and creates the potential for more cash flow volatility.

SMALL, LOW BUSINESS RISK, UNREGULATED OPERATIONS

Alliant maintains a small, low business risk, unregulated segment, Alliant Energy Finance (AEF, not rated) whose main assets are its investments in ATC and the Sheboygan Falls Energy Facility, a 347 MW simple-cycle natural gas fired power plant that is leased to sister company WPL until 2025 (lease payments are based on a 50% debt to capital ratio; 10.9% ROE). In addition, AEF is in the process of acquiring a 50% cash equity ownership interest in Great Western Wind, a 225 MW wind operating farm located in Oklahoma. The project supplies electricity to Google Inc. (Aa2 for its parent Alphabet Inc.) under a 15-year power purchase agreement.

Alliant transferred its merchant wind farm, Franklin County Wind Farm, to its sister company IPL in April 2017, a credit positive since the wind farm will now earn a regulated return rather than being exposed to volatile merchant pricing.

Structural Considerations

We apply a negative notch to Alliant's rating to capture the structural subordination of its parent-guaranteed AEF debt ($500 million as of 31 December 2016, 8% of consolidated debt), whose debt service ranks second to that of its utility debtholders.

Liquidity Analysis

Alliant's liquidity is adequate. As of 31 March 2017, Alliant had $8 million of cash on hand, $697 million of availability under $1 billion in total revolving credit facilities, and $98 million available under Alliant's parent-only, $300 million facility. The company also completed a $125 million equity issuance in June 2017 whose proceeds will, among other things, fund debt repayment.

Alliant has a significant maturity cliff during the second half of 2018 with $350 million of senior debentures due at IPL, a $500 million Term Loan due at the parent, as well as $1 billion of revolvers set to expire in December 2018. We expect that Alliant will renew and extend its three bank facilities before they go current in December 2017.

Borrowings under the three syndicated bank facilities are not subject to a material adverse change clause and contain a single financial covenant limiting the debt component of Alliant's capital structure to 65% for Alliant, and 58% for IPL and WPL. As of 31 March 2017, all three companies comfortably met their debt to capitalization covenant. Alliant's facility includes a cross-default provision that is triggered if one of Alliant's subsidiaries defaults on debt of $50 million or larger.

For LTM 31 March 2017, Alliant generated $965 million in cash flow from operations, invested $1.2 billion in capital investments, and distributed $272 million in dividends to its common shareholders, resulting in a negative free cash flow position of $556 million. The cash shortfall was funded through $530 million of debt and $26 million of equity. Going forward, we expect the company to remain free cash flow negative as it continues to target a 60-70% dividend payout ratio and executes on its capital investment plan of about $1.4 billion per year through 2020.

Corporate Profile

Headquartered in Madison, Wisconsin, Alliant Energy Corp. is the parent company of two vertically integrated utilities (total rate base $7.5 billion). Interstate Power and Light Company (IPL, Baa1 stable, 55% of consolidated rate base) and Wisconsin Power and Light Company (WPL, A2 stable, 45%). The company also holds a 16% ownership interest in American Transmission Company (ATC, A2 stable) . Alliant maintains minor unregulated operations consisting of a Midwest-based transportation business and 347 MW generation unit that operates under a long-term lease agreement with its sister company WPL.

For more information on WPL and IPL as well as our assessment of their respective regulatory environment, investment programs and fleet composition, please refer to their Credit Opinions dated July 2017 that can be found on moodys.com.

Rating Methodology and Scorecard Factors

Exhibit 3

Rating Factors				
Alliant Energy Corporation				
Regulated Electric and Gas Utilities Industry Grid [1][2]	**Current LTM 3/31/2017**		**Moody's 12-18 Month Forward View As of Date Published [3]**	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	5.9x	A	5.8x - 6.3x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	18.4%	Baa	16% - 19%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	13.4%	Baa	11% - 14%	Baa
d) Debt / Capitalization (3 Year Avg)	43.5%	A	43% - 46%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	-1	-1	-1	-1
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		Baa1		Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2017(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Ratings

Exhibit 4

Category	Moody's Rating
ALLIANT ENERGY CORPORATION	
Outlook	Stable
Issuer Rating	Baa1
Sr Unsec Bank Credit Facility	Baa1
Commercial Paper	P-2
INTERSTATE POWER AND LIGHT COMPANY	
Outlook	Stable
Issuer Rating	Baa1
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured	Baa1
Pref. Stock	Baa3
Commercial Paper	P-2
WISCONSIN POWER AND LIGHT COMPANY	
Outlook	Stable
Issuer Rating	A2
Sr Unsec Bank Credit Facility	A2
Senior Unsecured	A2
Pref. Shelf	(P)Baa1
Commercial Paper	P-1

Source: Moody's Investors Service

REPORT NUMBER 1074860

MOODY'S
INVESTORS SERVICE

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
7 February 2018

Update

Rate this Research

RATINGS

American Electric Power Company, Inc.

Domicile	Columbus, Ohio, United States
Long Term Rating	Baa1
Type	Senior Unsecured - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

American Electric Power Company, Inc.

Update following stable outlook

Summary

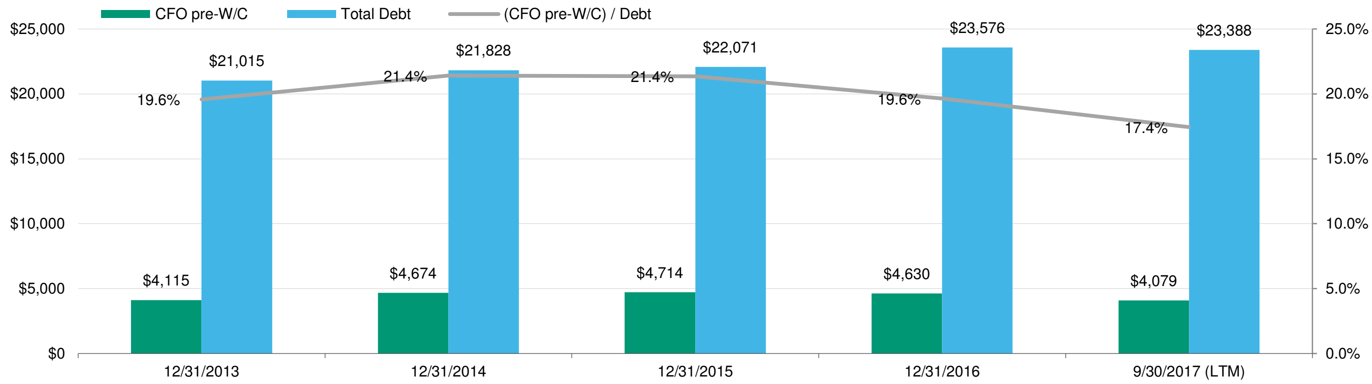
Our view of American Electric Power Company's (AEP) credit and stable outlook are underpinned by the size and diversity of its regulatory jurisdictions and service territories. AEP's nine retail utility subsidiaries operate under eleven different state regulatory bodies and its transmission subsidiaries are regulated by the Federal Energy Regulatory Commission (FERC). AEP benefits from a very stable earnings profile which over the past several years has yielded cash flow from operations pre-working capital (CFO pre-WC) to debt metrics in the high teens to low twenty percent range. In addition, cash flow stability is supported by AEP's current corporate strategy of focusing on its core regulated utility assets with more predictable earnings. Over the next few years, we expect that the recently enacted tax reform policy will result in downward pressure on AEP's consolidated financial metrics such that CFO pre-WC to debt will be in the mid-teens range.

In recent years, AEP has been successful in de-risking its business mix by reducing its exposure to the volatile merchant power markets; 2017 saw the successful sale of four Midwest merchant generating plants, and the consolidation, ownership-interest transfer and/or shutdown of others, a credit positive. With these completed transactions, AEP's remaining merchant exposure is approximately 3,000 MW and management continues to evaluate alternatives for these assets, which could include further transfers and/or shutdowns. Going forward, AEP's most significant growth area will be its transmission and distribution utilities and in 2017, we estimate that these less volatile businesses have contributed approximately 46% of AEP's consolidated cash flow.

Recent developments

In July 2017, AEP announced a plan for two of its subsidiaries, Southwestern Electric Power Company (SWEPCo) and Public Service Company of Oklahoma (PSO), to acquire the 2,000 MW Wind Catcher Energy Connection Project being developed by Invenergy, LLC (unrated); and to construct a 350-mile 765 kV power line which will carry power from the Oklahoma panhandle to the Tulsa area. The total cost for the Wind Catcher project, inclusive of about $1.6 billion for the transmission line, is estimated to be about $4.5 billion. SWEPCo will own about 70%, while PSO will own about 30%. AEP forecasts the project will save customers approximately $6.5 billion over 25 years. AEP's planned investment is contingent upon receipt of all state and federal regulatory approvals, which are needed by mid-2018 to assure project completion by the end of 2020 to qualify for federal wind production tax credits. Hearings in Arkansas, Louisiana, Oklahoma and Texas are scheduled in the first quarter of 2018 beginning with Texas and Oklahoma in January.

Exhibit 1
Historical CFO pre-WC, Total Debt, CFO pre-WC to Debt



Source: Moody's Financial Metrics

Credit strengths

» Diversity of regulatory jurisdictions and service territories provide a strong foundation for current rating

» History of regulatory support with timely and sufficient cost recovery

» Decreased business risk through exit of merchant business and focus on transmission and distribution investments

Credit challenges

» Substantial investments in regulated transmission networks and for environmental mandates will likely pressure credit metrics

» Weak demand growth in some large territories

Rating outlook

The stable outlook for AEP reflects its diversified regulatory jurisdictions and service territories and our expectation that those jurisdictions will remain credit supportive and not prevent or materially delay the recovery of prudently incurred costs. The outlook also considers AEP's prudent financial management and our expectation that cash flow impacts of tax reform may cause credit metrics to weaken including CFO pre-WC to debt falling into the mid-teens range, unless mitigated by regulatory actions or changes in corporate finance policies.

Factors that could lead to an upgrade

» A ratio of CFO pre-WC to debt in the high teens range on a sustainable basis

» An upgrade of one or more AEP's largest utility subsidiaries

Factors that could lead to a downgrade

» If a more contentious regulatory environment were to develop in any of its key jurisdictions

» If environmental and nuclear investments cannot be recovered on a timely basis

» If AEP's financial metrics were to deteriorate on a sustained basis resulting in CFO pre-WC to debt below 15%

Key indicators

Exhibit 2

KEY INDICATORS [1]

American Electric Power Company, Inc.

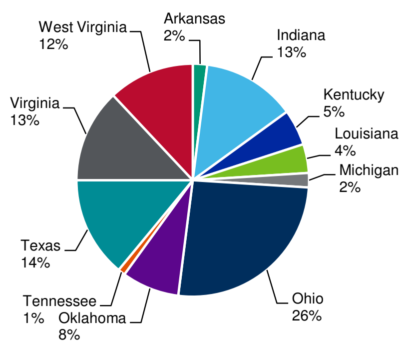
	12/31/2013	12/31/2014	12/31/2015	12/31/2016	9/30/2017(L)
CFO pre-WC + Interest / Interest	5.1x	6.0x	5.8x	5.7x	5.2x
CFO pre-WC / Debt	19.6%	21.4%	21.4%	19.6%	17.4%
CFO pre-WC – Dividends / Debt	15.0%	16.8%	16.6%	14.9%	12.5%
Debt / Capitalization	44.3%	44.1%	42.8%	44.7%	43.4%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Source: Moody's Financial Metrics™
Source: Moody's Financial Metrics

Profile

American Electric Power Company, Inc. (AEP: Baa1 stable), headquartered in Columbus, Ohio, is a large electric utility holding company with nine vertically integrated or retail transmission and distribution utility subsidiaries operating in eleven states. The company also operates transmission companies within the eastern and southwestern regions of the United States and owns a predominately Ohio based competitive generation and marketing business which has been mostly sold and for which it is evaluating strategic alternatives. AEP has a regulated rate base of over $35 billion and serves about 5.4 million customers. In 2017, the company's generation capacity totaled approximately 33,082 MW and is about 47.2% coal/lignite fired.

Exhibit 3
2016 percentage breakdown of AEP system retail revenues



Source: Company presentations

Detailed credit considerations

Diversity of regulatory jurisdictions and service territories provides a strong foundation for current credit profile

AEP's diversity in terms of regulatory jurisdictions and service territory economies is a meaningful credit strength as it provides the company with a degree of insulation from any unexpected negative developments occurring at any one of its operating companies, state regulatory bodies or state economies. This diversity has been helpful in dealing with weak demand growth in some of AEP's service territories while it spends heavily on environmental compliance and system reliability. Going forward, the largest portion of AEP's capital program will be for investment in its federally regulated transmission subsidiaries along with increased investment in transmission and distribution operations at its state regulated utility subsidiaries.

AEP's primary state regulated utilities and their respective authorities are as follows: Ohio Power Company (OPCo: A2 stable), which accounted for 18% of AEP's total 2016 revenues, operates under the Public Utility Commission of Ohio (PUCO); Appalachian Power Company (APCo: Baa1 stable), which accounted for 18% of AEP's total 2016 revenues, operates under the Virginia State Corporation Commission (VSCC), (covering a little over half of APCo's customers) and the more challenging Public Service Commission of West

Virginia (PSC WV); Indiana Michigan Power Company (I&M: Baa1 positive), 13% of AEP's total 2016 revenues, regulated by the Indiana Utility Regulatory Commission (IURC), (about ¾ of I&M's customers) and the Michigan Public Service Commission (MPSC); Southwestern Electric Power Company (SWEPCo: Baa2 stable), 11% of AEP's total 2016 revenues, operates under the Louisiana Public Service Commission (LPSC) (about 43% of SWEPCo customers), the Arkansas Public Service Commission (ARPSC) (22% of SWEPCo customers) and the Public Utility Commission of Texas (PUCT) (35% of SWEPCo customers); Public Service Company of Oklahoma (PSO: A3 negative), 8% of AEP's total 2016 revenues, regulated by the Oklahoma Corporation Commission (OCC); AEP Texas (AEP Texas: Baa1 stable), which was formed by the merger of AEP Texas Central and AEP Texas North Company at year-end 2016, 9% of AEP's total 2016 revenues, regulated by the Public Utility Commission of Texas (PUCT); and Kentucky Power Company (KPCo: Baa2 stable), 4% of AEP's total 2016 revenues, under the Kentucky Public Service Commission (KPSC).

AEP Transmission Company LLC's (AEP Transco: A2 stable) transmission businesses are regulated by the FERC under forward looking formulaic rate plans that result in a high degree of cash flow predictability. Operations are actively conducted through six subsidiaries within AEP's electric utility service territories in seven states: Ohio, West Virginia, Kentucky, Oklahoma, Tennessee, Indiana and Michigan.

Exhibit 4
Regulated rate base by subsidiary as of September 30, 2017
($ in millions)

Source: Company presentations

For further information on these service territories and subsidiaries please refer to each utility's credit opinion on Moodys.com.

Continued regulatory support with timely and sufficient cost recovery important to credit quality

Given the significant amount of capital expenditures AEP has planned across its regulated business segments, it is essential that the company maintains a supportive relationship with its regulators to sustain credit quality. The utility subsidiary ratings and outlooks reflect our view that AEP will continue to receive timely and consistent long-term regulatory support across the majority of its jurisdictions. Recent regulatory filings, orders and updates for AEP are as follows:

OPCo – The PUCO continues to demonstrate a credit supportive view for utilities operating in the state. For the last several years, utilities have been operating under individually tailored electric security plans (ESPs), which are rate plans for the supply and pricing of electric generation service. OPCo's current ESP runs through May 2018. In August 2017, OPCo and various intervenors filed a settlement agreement with the PUCO extending the term of the ESP through May 2024. Provisions of the settlement include OPCo's agreement to file a base electric distribution rate case by June 2020, a quarterly adjusted distribution investment rider to remain in place through May 31, 2024, along with annual revenue caps and a return on equity (ROE) of 10% on capital costs for certain riders. In October 2017, intervenor testimony opposing the stipulation agreement was filed recommending a ROE that did not exceed 9.3% on riders earning a return on capital investments. A hearing at the PUCO was held in November 2017.

APCo (Virginia) – APCo's relationship with the VSCC has generally been constructive. The utility benefits from various riders and trackers that currently incorporate an ROE of 9.4%, which is near the top of the range of 8.5% to 9.5% the VSCC determined was reasonable.

Virginia historically had biennial reviews of investor owned utility earnings; however, in February 2015, Virginia enacted legislation temporarily suspending the required biennial review, effectively freezing rates for APCo through the 2017 test year. Biennial reviews are to begin again in 2020 addressing results for the 2018 and 2019 test years. This is positive for APCo considering its last biennial review decision (issued November 2014) found that for the 2012 and 2013 test years APCo had on average earned an 11.86% ROE, which was above the upper end of the 10.4%-11.4% allowed range established for those years.

In April 2017, oral arguments relating to an appeal filed by industrial customers in July 2016 were held before the Supreme Court of Virginia. In September 2017, the Supreme Court of Virginia affirmed the VSCC's 2016 order.

I&M (Indiana – about 65% of system demand) – In July 2017, I&M filed with the IURC, seeking a $263 million rate increase premised upon on a 10.6% ROE, 35.21% equity layer of regulatory capital structure and rate base valuation of $4.2 billion for a 2018 test year. The rate increase is to be implemented after June 2018 and would be subject to a temporary offsetting $23 million annual reduction to customer bills through December 2018. The offset stems from an adjustment rider related to the timing of estimated in-service dates of certain capital investments, with the full rate increase to be in place in early 2019. The proposed increase incorporates higher depreciation rates related to the expected early retirement of Rockport Unit 1 as well as increased investment at the Cook nuclear plant, including the Cook Plant Life Cycle Management (LCM) project. Hearings began in January 2018 and an order is anticipated by July 2018. I&M currently operates under a 10.2% authorized ROE and 43% regulated equity layer, as established by its 2011 rate case.

I&M (Michigan – about 15% of system demand) – In May 2017, I&M filed a rate case with the MPSC, requesting a $51.7 million electric rate increase premised upon a 10.6% ROE, 36% equity layer of regulatory capital structure and rate base valuation of $1.015 billion for a calendar 2018 test year. The rate increase request is mainly driven by costs associated with the Cook Plant LCM project as well as costs associated with electric delivery system updates, vegetation management, and higher depreciation costs for a coal plant. Under Michigan statues, the MPSC is must render a final decision within ten months of the filing or the requested increase would be automatically approved. In October 2017, the MPSC staff and intervenors filed testimony, with the staff recommending an annual net revenue increase of $49 million including proposed retirement dates of 2028 for both Rockport Plant, Units 1 (from 2044) and 2 (from 2022) and a ROE of 9.8%. The intervenors proposed certain adjustments including no change to the current 2044 retirement date of Rockport Plant, Unit 1 and recommended ROEs in the range of 9.3% to 9.5%. An order is anticipated by April 2018. I&M currently operates under a 10.2% authorized ROE and 42% regulated equity layer, as established by its 2011 rate case.

SWEPCo (Texas – about 35% of customers) – On December 16, 2016, SWEPCo filed with the PUCT, seeking a net annual revenue increase of $69 million ($105.9 million increase in base rates offset by amounts currently being collected in riders). The proposed increase was premised upon a 10.0% ROE and includes approximately $34 million relating to additional environmental controls and $8 million related to transmission cost recovery. In April and May 2017, various intervenors and the PUCT staff recommended annual net revenue increases ranging from $36 million to $47 million, reflecting ROEs ranging from 9.2% to 9.35%. The intervenors also disagreed with SWEPCo's proposed transmission cost recovery mechanism. Hearings were held in June 2017 and in September 2017, and the Administrative Law Judges (ALJs) proposed an annual net revenue increase of $50 million including recovery of Welsh Plant, Unit 2 environmental investments as of June 30, 2016. On January 11, 2018, the PUCT authorized a net annual revenue increase of $50 million ($86.9 million increase in base rates offset by amounts currently being collected in riders) based on a 9.6% ROE and 48.5% equity layer to be implemented retroactively to May 20, 2017. In addition, the final order also called for the implementation of a deferral mechanism to address the ramifications of the reduction in income tax rates due to the recently enacted tax reform law. SWEPCo's last Texas rate case was decided in 2013 when the PUCT approved an approximate $52 million rate increase based on a 9.65% ROE and a 49% equity layer.

In July 2017, SWEPCo submitted filings with the LPSC, ARPSC and PUCT requesting the necessary regulatory approvals needed to proceed with the Wind Catcher project. Intervenor testimonies in Texas and Arkansas were filed in the beginning of December, with some Texas intervenors opposing the project on the grounds that the projected customer savings that AEP had outlined were inflated. Hearings in all jurisdictions are scheduled to begin in Q1 2018.

PSO – In June 2017, PSO filed for a base rate increase request with the OCC, proposing a net increase in annual revenues of $156 million premised upon a 10.0% ROE, 48.5% equity layer and $2.5 billion rate base valuation. The request was driven largely by recovery on federal environmental compliance investments and infrastructure investments. In September 2017, various intervenors and the OCC staff filed testimonies, with the staff recommending a revenue increase of approximately $132 million. In December, an administrative law judge recommended PSO be authorized an increase of $81 million based on a 9% ROE. In January 2018, the OCC issued a final order authorizing a revenue increase of approximately $111 million based on a 9.3% ROE and 48.5% equity later.

In July 2017, PSO submitted filings with the OCC requesting the necessary regulatory approvals needed to proceed with the Wind Catcher project. In August 2017, the Oklahoma Attorney General filed a motion to dismiss with the OCC, which was subsequently denied. Intervenors in Oklahoma filed testimony opposing the project in early December, criticizing the price assumptions used in forecasting customer savings, similar to the case in Texas. Hearings are expected to begin in early January 2018.

AEP Texas – At the end of August 2017, AEP Texas' operations were impacted by Hurricane Harvey, a Category 4 storm that was the most severe to hit the utility's service territory in 44 years. At its peak, approximately 220,000 (over 20%) of AEP Texas' customers in the Corpus Christi and surrounding areas did not have electric service. The current estimated cost is approximately $325 million to $375 million, including capitalized expenditures and approximately $100 million of operation and maintenance costs related to its restoration efforts. Given the regulatory mechanisms in Texas, AEP Texas will be able to defer these costs for future collection, and will have the option to securitize some or all of the expenditures. The impact on credit metrics is also manageable.

KPCo – In June 2017, KPCo filed with the KPSC, seeking an annual rate increase of approximately $65.4 million, incorporating a 10.31% ROE, 42% equity layer and $1.2 billion rate base valuation for a test year ending February 2017. The proposed increase was largely driven by a drop in customer load and recovery associated with its Big Sandy Plant, Unit 1. In August 2017, KPCo lowered its rate increase request to $60 million, stemming from a lower interest expense related to June 2017 debt refinancings. In October 2017, various intervenors filed testimony that included annual net revenue increase recommendations ranging from $13 million to $40 million and recommended ROEs in the range of 8.6% to 8.85%. In November 2017, KPCo reached an agreement with intervenors and filed a non-unanimous settlement with the KPSC that included a $31.8 rate increase premised on a 9.75% ROE and included a three year stay-out provision.

On January 18, 2018, the KPSC issued an order authorizing a $12.4 million base rate increase reflecting a 9.7% ROE and 42% equity later. The noticeable differential between the authorized increase and the amount agreed upon in the settlement was primarily driven by a $13.9 million reduction, reflecting the effects of federal tax rate cuts. Furthermore, the KPSC discontinued nearly all of KPCo' demand-side management programs for both residential and commercial customers.

AEP Transco – The AEP Transco subsidiaries are currently allowed a return of 11.49% in PJM and 11.20% in SPP. In various parts of the country, most recently including SPP, challenges have been filed to certain FERC approved ROEs that were viewed as being high as compared to those approved for state regulated utilities. In June 2017, several parties filed a joint complaint with the FERC seeking a reduction in the ROEs used for western AEP Transcos that operate in SPP, to 8.36% from 10.7%. In October 2016, American Municipal Power, Inc. (AMP, A1 Issuer Rating stable) and several other parties filed a joint complaint with the FERC seeking a reduction in the ROE for AEP's transmission owning subsidiaries operating in PJM to 8.82% (8.32% base plus 0.5% RTO adder). We note that management previously identified the range of transmission ROEs in PJM to be 10.5% - 12.4%. We also note that in recent FERC rulings on similar cases in New England and MISO, although ROEs were lowered, they remained above 10%. If the FERC were to lower the authorized ROE for AEP Transco's operating subsidiaries, it could reduce future net income and thereby negatively affect cash flows.

The AEP Transco subsidiaries receive revenues based on FERC approved formulaic tariffs that are set to allow the recovery of all of the companies expenditures for operations, maintenance, depreciation and taxes plus a return on forward looking capital investment. In November 2016, AEP East Transcos filed a FERC 205 application to modify their formula rate plans to include forward looking, rather than historical, recovery of expenses, thereby transitioning to fully projected formula rates. In March 2017, the FERC issued an order approving the modifications, effective January 1, 2017, subject to refund. In October 2017, AEP West Transcos filed a similar 205 application, which is still pending at the FERC.

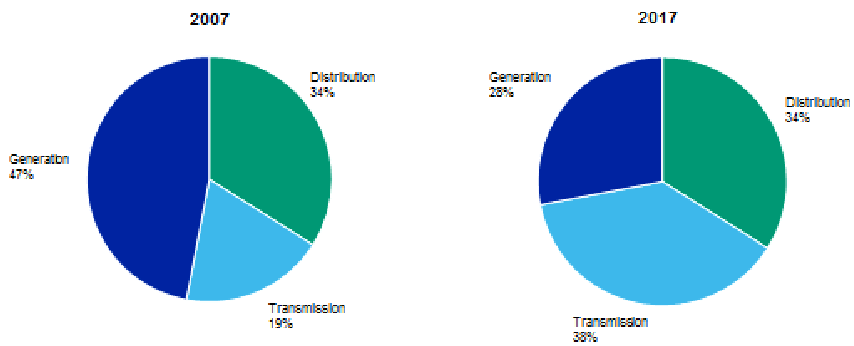
For more details regarding any of AEP's subsidiaries regulatory updates please refer to their pages on Moodys.com.

Substantial investments in regulated transmission networks and environmental mandates

AEP has been investing heavily in its transmission and distribution networks to assure reliability throughout its service territories. AEP's current capital program includes approximately $17.7 billion of investment planned for 2018 through 2020. This average projected capital spending of approximately $6 billion per year, which is comparable to 2017 levels, is higher than the $4.8 billion spent in 2016 and $4.6 billion spent in 2015, and represents a substantial increase from the $3.1 billion invested in 2012 and $2.8 billion in 2011.

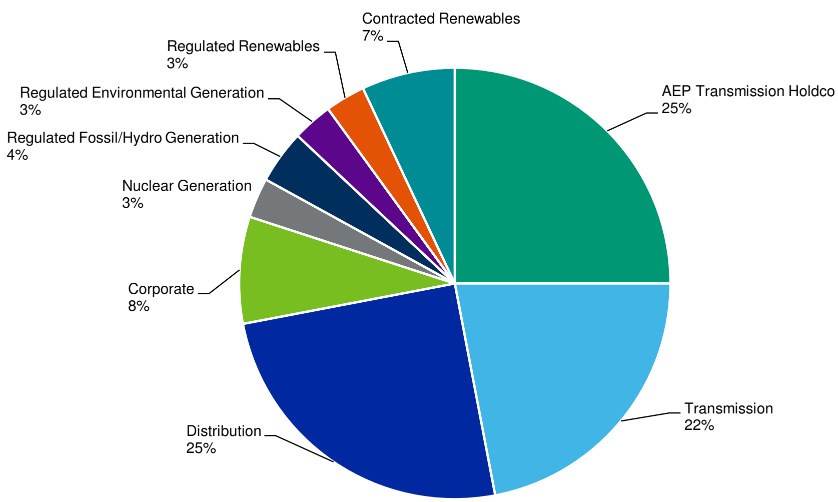
All of the total $17.7 billion will be allocated to regulated businesses and contracted renewables as follows: transmission 47%, distribution 25%, regulated generation 10%, contracted renewables 7%, corporate 8% and regulated renewables 3%. The focus on transmission and distribution investing has resulted in a shift of net plant. As shown below, AEP's current net plant profile in 2017 totals approximately $43.8 billion and consists of: transmission 38%, distribution 34%, and generation 28%. This compares with a net plant profile in 2007 of: generation 47%, distribution 34%, and transmission 19%, highlighting the changing composition of AEP's operations into lower risk businesses.

Exhibit 5
Net plant profile composition over the last ten years had shifted towards more transmission



Source: Company presentations

Exhibit 6
Capital forecast from 2018 through 2020 totals $17.7B and focuses on transmission assets



Source: Company presentations

Transmission and distribution (T&D) investments are expected to be recovered largely either through the transmission formula based rates or rider recovery, a credit positive. Generation investment is primarily recovered in base rates and more susceptible to lags in recovery. Given the sheer magnitude of the investment program, we anticipate intermediate term credit metrics could deteriorate somewhat.

Additional debt financing for capex spend will put downward pressure on financial metrics – exacerbated by tax reform but mitigated by an investment strategy focused on transmission and distribution

AEP's key financial metrics have historically been strong for its rating. As of the last twelve months ending (LTM) Q3 2017, AEP's adjusted three year average interest coverage ratio was 5.8 times and CFO pre-WC to debt was about 20.8%, which respectively fall in the high "A" and "Baa" scoring ranges for these factors as indicated in our rating methodology for standard risk regulated electric and gas utilities. These metrics are similar to those observed for Xcel Energy Inc. (A3 stable) and stronger than those of Duke Energy Corporation (Baa1 negative), which are also both large, multistate utility holding companies with virtually all regulated or contracted operations and relatively low business risk.

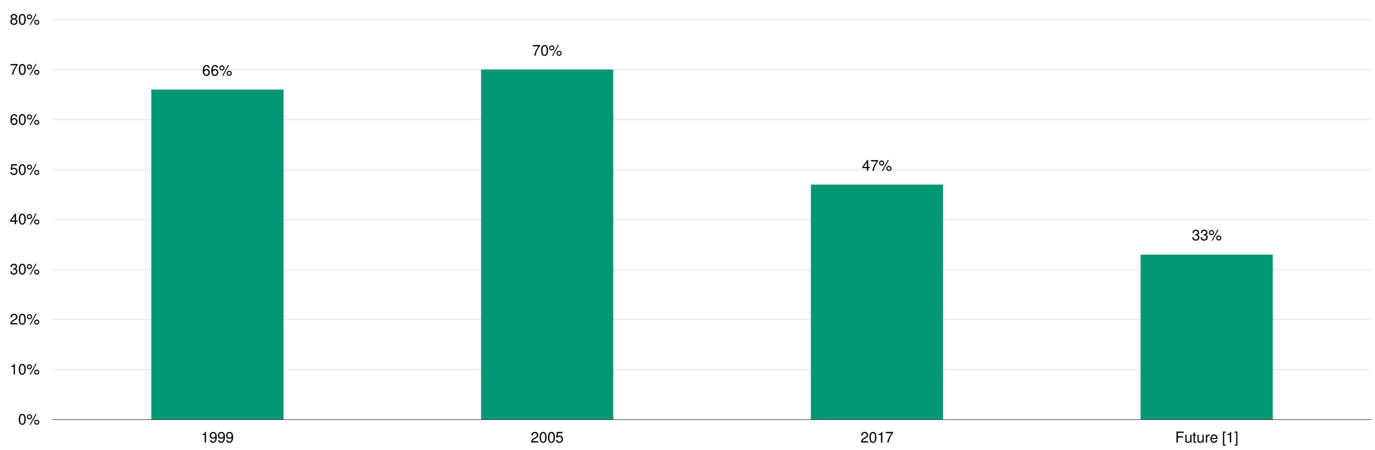
Going forward, we expect AEP's financial metrics to deteriorate slightly as the company continues to incur debt to fund its capital expenditure program and as recently enacted tax reform reduces utility cash flow. However, we expect credit metrics to remain appropriate for AEP's current Baa1 rating, particularly when viewed in light of its diverse, primarily supportive regulatory environments and the strategic focus of its capital expenditure plans. For example, we anticipate an interest coverage ratio in the 5.0x-5.5x range and CFO pre-WC to debt in the mid-teens.

Environmental sustainability

Although still heavily reliant on coal generation, AEP is focused on transitioning to a cleaner energy future that is more responsive to consumers' needs by investing in the resilience and interoperability of its transmission and distribution systems and rebalancing its generation portfolio to include more renewables while reducing coal-fired exposure. Since 2000, AEP estimates that capital investment to reduce emissions have totaled approximately $8.7 billion. As of 2017, AEP's consolidated generating portfolio included about 47% coal-fired resources, versus about 66% in 1999. As a result, the company estimates that in 2017, its carbon emissions will be 56 percent below 2000 levels, including the effects of the sale of coal and natural gas assets in early 2017. AEP's goal is to integrate energy efficiency, clean energy sources, and advanced technology into the essential energy services they provide, and to give consumers more choices.

Exhibit 7

Total coal capacity has significantly decreased from historical levels and is expected to continue



[1] Future includes Integrated Resource Plan forecasted additions and retirements through 2030; excludes Wind Catcher
Source: Company presentations

Liquidity analysis

We expect AEP to maintain an adequate liquidity profile over the next 12-18 months. Although we anticipate its significant investment program will result in negative free cash flow for the foreseeable future, the company has demonstrated capital markets access and its credit facilities currently provide reasonable near-term protection.

For the twelve months ending September 30, 2017, AEP generated approximately $4.2 billion of cash from operations (CFO), invested $5.2 billion in capital expenditures and paid $1.2 billion in dividends resulting in a negative free cash flow (FCF) of approximately $2.2 billion, on a reported basis. In 2016, AEP generated approximately $4.5 billion of CFO, invested $4.8 billion in capital expenditures and paid $1.1 billion in dividends resulting in a negative FCF of approximately $1.5 billion. Going forward, given AEP's substantial level of planned capital expenditures, we anticipate the company will continue to generate negative free cash flow, which will be funded via a combination of internal and external sources including debt financing.

AEP currently has one syndicated credit facility totaling $3.0 billion, with a $1.2 billion letter of credit sub-limit, expiring in June 2021. As of September 30, 2017, AEP had $295 million of commercial paper outstanding and no letters of credit outstanding under the facilities. In addition, AEP has a receivables securitization agreement of $750 million that expires in June 2019.

AEP is not required to make a representation with respect to either material adverse change or material litigation in order to borrow under the facilities. Default provisions exclude non-significant subsidiaries' (including AGR) cross-default and insolvency/bankruptcy provisions. The facilities contain a covenant requiring that AEP's consolidated debt to capitalization (as defined) not exceed 67.5%. AEP states the contractually defined ratio was 52.4% at September 30, 2017.

At September 30, 2017, AEP had consolidated long-term debt due within one year of approximately $2.36 billion, including $550 million in senior notes at the holding company level maturing in December 2017. In November 2017, AEP issued two series of senior notes totaling $1 billion, of which $500 million is due in November 2020 and $500 million is due in November 2027. The proceeds were used for general corporate purposes, including the repayment at maturity of the $550 million in senior notes due in December 2017 and the repayment of $295 million in commercial paper outstanding.

Structural considerations

AEP's rating reflects the limited amount of structural subordination that exists within the consolidated organization. As of December 2017, AEP had long-term parent level debt obligations of $1.3 billion, or about 6% of AEP's consolidated long-term total debt. It is our view that, within the context of our methodology scorecard grid, considering the modest level of parent holding company debt relative to total consolidated debt, the diversity of subsidiaries, and the low level of overall business risk, we do not apply any structural subordination notching. The weighted average rating of AEP's subsidiary debt is currently Baa1; on the basis of cash flow, the weighted average is currently A3. AEP's fastest growing subsidiary AEP Transmission Company, is rated A2.

Rating methodology and scorecard factors

Exhibit 8

Rating Factors				
American Electric Power Company, Inc.				
Regulated Electric and Gas Utilities Industry Grid [1][2]	**Current LTM 9/30/2017**		**Moody's 12-18 Month Forward View As of Date Published [3]**	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	5.8x	A	4.5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	20.8%	Baa	14% - 17%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	15.9%	Baa	11% - 14%	Baa
d) Debt / Capitalization (3 Year Avg)	43.3%	A	48% - 52%	Baa
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching				
a) Indicated Rating from Grid		A3		A3
b) Actual Rating Assigned		Baa1		Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/2017(L); Source: Moody's Financial Metrics™
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Appendix

Exhibit 9

Cash Flow and Credit Measures [1]

	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	LTM 09/30/2017
FFO	**$4,250**	**$4,258**	**$4,435**	**$4,856**	**$4,897**	**$4,396**
+/- Other	($47)	($143)	$239	($142)	($267)	($317)
CFO Pre-W/C	**$4,203**	**$4,115**	**$4,674**	**$4,714**	**$4,630**	**$4,079**
+/- ΔWC	($52)	$246	$183	$223	$27	$282
CFO	**$4,151**	**$4,361**	**$4,856**	**$4,936**	**$4,657**	**$4,360**
- Div	$916	$954	$998	$1,059	$1,121	$1,166
- Capex	$3,339	$4,033	$4,493	$4,783	$5,039	$5,376
FCF	**($104)**	**($626)**	**($635)**	**($906)**	**($1,503)**	**($2,182)**
Total Debt	**$21,198**	**$21,015**	**$21,828**	**$22,071**	**$23,576**	**$23,388**
(CFO Pre-W/C) / Debt	**19.8%**	**19.6%**	**21.4%**	**21.4%**	**19.6%**	**17.4%**
(CFO Pre-W/C - Dividends) / Debt	**15.5%**	**15.0%**	**16.8%**	**16.6%**	**14.9%**	**12.5%**
FFO / Debt	**20.1%**	**20.3%**	**20.3%**	**22.0%**	**20.8%**	**18.8%**
RCF / Debt	**15.7%**	**15.7%**	**15.7%**	**17.2%**	**16.0%**	**13.8%**

[1] All figures & ratios calculated using Moody's estimates & standard adjustments.
Source: Moody's Financial Metrics

Exhibit 10

Peer Comparison Table [1]

	American Electric Power Company, Inc. Baa1 Stable			Xcel Energy Inc. A3 Stable			Duke Energy Corporation Baa1 Negative			Southern Company (The) Baa2 Negative		
(in US millions)	FYE Dec-15	FYE Dec-16	LTM Sep-17	FYE Dec-15	FYE Dec-16	LTM Sep-17	FYE Dec-15	FYE Dec-16	LTM Sep-17	FYE Dec-15	FYE Dec-16	LTM Sep-17
Revenue	$16,453	$16,380	$15,405	$11,024	$11,107	$11,403	$22,371	$22,743	$23,343	$17,489	$19,896	$22,583
CFO Pre-W/C	$4,714	$4,630	$4,079	$2,980	$3,178	$3,313	$6,833	$6,685	$6,855	$6,299	$4,524	$6,277
Total Debt	$22,071	$23,576	$23,388	$14,815	$15,907	$16,457	$41,536	$49,601	$52,532	$30,644	$48,956	$51,513
(CFO Pre-W/C + Interest) / Interest Expense	5.8x	5.7x	5.2x	6.0x	5.9x	6.0x	5.1x	4.4x	4.4x	7.2x	4.0x	4.5x
(CFO Pre-W/C) / Debt	21.4%	19.6%	17.4%	20.1%	20.0%	20.1%	16.5%	13.5%	13.1%	20.6%	9.2%	12.2%
(CFO Pre-W/C - Dividends) / Debt	16.6%	14.9%	12.5%	16.0%	15.7%	15.8%	11.0%	8.8%	8.4%	15.2%	6.1%	8.2%
Debt / Book Capitalization	42.8%	44.7%	43.4%	46.9%	47.2%	46.7%	44.2%	47.3%	48.0%	47.0%	54.2%	55.5%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months.
Source: Moody's Financial Metrics

Ratings

Exhibit 11

Category	Moody's Rating
AMERICAN ELECTRIC POWER COMPANY, INC.	
Outlook	Stable
Senior Unsecured	Baa1
Jr Subordinate Shelf	(P)Baa2
Commercial Paper	P-2
SOUTHWESTERN ELECTRIC POWER COMPANY	
Outlook	Stable
Issuer Rating	Baa2
Senior Unsecured	Baa2
APPALACHIAN POWER COMPANY	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1
Other Short Term	P-2
INDIANA MICHIGAN POWER COMPANY	
Outlook	Positive
Issuer Rating	Baa1
Senior Unsecured	Baa1
Other Short Term	P-2
AEP TRANSMISSION COMPANY, LLC	
Outlook	Stable
Issuer Rating	A2
Senior Unsecured	A2
COLUMBUS SOUTHERN POWER COMPANY	
Outlook	No Outlook
Senior Unsecured	A2
OHIO POWER COMPANY	
Outlook	Stable
Issuer Rating	A2
Senior Unsecured	A2
PUBLIC SERVICE COMPANY OF OKLAHOMA	
Outlook	Negative
Issuer Rating	A3
Senior Unsecured	A3
AEP TEXAS INC.	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1
AEP TEXAS CENTRAL COMPANY	
Outlook	No Outlook
Senior Unsecured	Baa1
RGS (AEGCO) FUNDING CORPORATION	
Outlook	Positive
Bkd Senior Secured	Baa1
RGS (I&M) FUNDING CORPORATION	
Outlook	Positive
Bkd Senior Secured	Baa1
KENTUCKY POWER COMPANY	
Outlook	Stable
Issuer Rating	Baa2
Senior Unsecured	Baa2

Source: Moody's Investors Service

REPORT NUMBER 1109561

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Moody's
INVESTORS SERVICE

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
19 March 2018

Update

Rate this Research

RATINGS

Duke Energy Progress, LLC

Domicile	North Carolina, United States
Long Term Rating	A2
Type	LT Issuer Rating
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Asia Pacific 852-3551-3077

Japan 81-3-5408-4100

EMEA 44-20-7772-5454

Duke Energy Progress, LLC

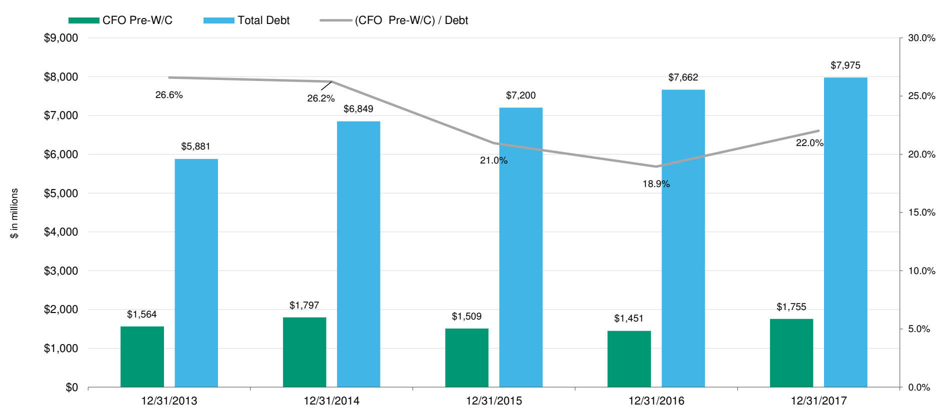
Update to credit analysis

Summary

Duke Energy Progress, LLC's credit reflects its business and operating risk profile as a fully regulated utility with service territories in supportive environments in both North and South Carolina, as exemplified by recent approvals for recovery of, and return on, expenditures relating to coal ash remediation. Current financial metrics are below historic highs, however we expect them to remain near 2017 levels and appropriate for the A2 rating. The decline in financial metrics in 2015 and 2016 was due primarily to increased debt from a 2015 acquisition, and to fund coal ash basin remediation and other capital expenditures, as well as costs associated with Hurricane Matthew in 2016. This was a contributing factor in the January 2016 downgrade of Duke Energy Progress to A2 from A1.

Exhibit 1

Historical CFO pre-W/C, total debt and CFO pre-W/C to debt



Source: Moody's Financial Metrics

Credit strengths

» Credit supportive regulatory environments

» Appropriate financial credit metrics

Credit challenges

» Regulatory lag in the recovery of coal ash spending could maintain negative pressure on metrics

» Capital expenditures for coal ash basin remediation and T&D upgrades will remain substantial

Rating outlook

The stable rating outlook reflects the utility's relatively low business risk profile, credit supportive regulatory frameworks, and a cash flow pre-working capital to debt ratio that we anticipate will remain in the low 20% range. The outlook reflects our expectation that Duke Energy Progress' sizeable capital expenditure program will be well managed and that debt levels will be maintained at levels appropriate for an A2 rating. The stable outlook also reflects our expectation that, consistent with recent rate case outcomes, the company will be able to recover the majority of its coal ash closure and remediation costs in rates, although regulatory lag and the impact of federal tax reform may continue to pressure metrics to a modest degree.

Factors that could lead to an upgrade

» A reduction in leverage, possibly due to lower spending for capital expenditures

» A ratio of cash flow from operations excluding changes in working capital (CFO pre-W/C) to debt above 25% on a sustained basis

Factors that could lead to a downgrade

» A decline in the credit supportiveness of the regulatory environments in North or South Carolina

» A ratio of CFO pre-W/C to debt below 20% on a sustained basis

Key indicators

Exhibit 2
Duke Energy Progress, LLC Indicators[1]

	Dec-13	Dec-14	Dec-15	Dec-16	Dec-17
CFO pre-WC + Interest / Interest	7.4x	8.0x	6.5x	5.9x	6.3x
CFO pre-WC / Debt	26.6%	26.2%	21.0%	18.9%	22.0%
CFO pre-WC – Dividends / Debt	26.6%	23.0%	21.0%	15.0%	20.5%
Debt / Capitalization	41.9%	43.8%	41.8%	41.9%	45.0%

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

Duke Energy Progress, LLC is a vertically integrated electric utility serving approximately 1.5 million customers in North Carolina and South Carolina. Duke Energy Progress is a subsidiary of intermediate holding company Progress Energy, Inc. and parent company Duke Energy Corporation (Duke).

Detailed credit considerations

Credit supportive regulatory environments

Duke Energy Progress has service territories in both North and South Carolina, two fully regulated states with generally credit supportive regulatory environments. In North Carolina, the North Carolina Utilities Commission (NCUC) in February 2018 authorized an approximate $193 million (6%) annual increase in base rates (reduced by $43 million for four years to return excess state income tax) incorporating a return on equity (ROE) of 9.9% and a 52% equity ratio. The final order authorized a partial settlement agreement between Duke Energy Progress and the North Carolina Utilities Commission Public Staff with regard to certain, traditional rate making parameters, including the ROE and equity ratio, and also resolved the outstanding issues of coal ash and storm cost recovery discussed below.

The February order incorporated recovery of the majority of deferred coal ash remediation costs ($232 million) over five years with an ability to earn a return at Duke Energy Progress' weighted average cost of capital (debt and equity). The NCUC also authorized recovery and return for $51 million (out of $80 million requested) of deferred storm costs incurred for Hurricane Matthew restoration. We view the ability to reach a settlement agreement on traditional ratemaking parameters, and the approval for the recovery of coal ash and storm costs with a return, as credit positive.

The NCUC did not approve Duke Energy Progress' request for ongoing recovery of coal ash remediation spending (estimated at $129 million per year). As such, the company will continue to experience regulatory lag as it complies with these requirements and defers the associated costs for future recovery. Absent a tracking mechanism, we expect the utility will seek to minimize this lag through frequent rate filings. The NCUC also assessed a management penalty of $30 million for Duke Energy Progress, which will reduce annual recovery by $6 million per year for five years. The base rate case did not address the impact of federal tax reform, or the potential implementation of a tracking mechanism for future investments in grid modernization and resiliency. We anticipate these items will be addressed in future proceedings. We would view the approval of riders or trackers to accelerate the recovery of costs for grid modernization and/or coal ash remediation as credit positive.

The North Carolina case was initiated in June 2017 when Duke Energy Progress filed for a $447 million (subsequently revised to $420 million) annual increase premised on an ROE of 10.75% and a 53% equity ratio. The company's prior rate decision was rendered in May 2013, when Duke Energy Progress reached a three year settlement agreement allowing a 10.2% return on equity (ROE) with a 53% equity layer.

In South Carolina (approximately 10% of earnings base), in December 2016, the Public Service Commission of South Carolina (PSCSC) approved a $56 million rate increase settlement based on a 10.1% ROE and a 53% equity ratio. The increase was implemented in two steps, with an incremental $37.7 million or 6.93% effective beginning January 2017 and an additional $18.5 million or 3.40% effective January 2018. The company also received authorization to begin the recovery of coal ash remediation costs incurred through June 2016 over a 15 year period, and to continue to defer costs, and a return, on expenditures made after that date. Prior to this approval, the utility had not filed a rate case in the state since 1988. As a part of the settlement Duke Progress will not seek to implement new rates prior to January 2019.

Part of the Duke corporate family

Duke Energy Progress' credit profile reflects its position as part of the Duke corporate family and the largest utility system in the Carolinas, benefitting from fuel purchasing power and joint generation dispatch synergies with affiliate Duke Energy Carolinas.

Financial metrics are expected to be maintained near current levels

The rating of Duke Energy Progress reflects financial metrics and cash flow coverage ratios that were historically strong, but have more recently weakened. In 2015 and 2016, metrics declined due to increased capital expenditures, the addition of debt to fund the 2015 purchase of the North Carolina Eastern Municipal Power Agency's (NCEMPA) ownership interest in generation assets, delays in recovering costs associated with coal ash remediation, and the 2016 impact of Hurricane Matthew. Going forward, we expect some improvement as the company implements its recent North Carolina rate order, which includes the recovery of previously incurred coal ash expenditures. However, some regulatory lag will continue, and cash flow is likely to be negatively impacted by federal tax reform legislation. As a result, we expect credit metrics may remain near the levels demonstrated in 2017.

For the year ending December 2017, Duke Energy Progress generated a ratio of cash flow from operations excluding changes in working capital (CFO pre-WC) to debt of approximately 22%. This ratio is negatively impacted by the accounting treatment of coal ash remediation spending, adjusting for this, the ratio would be above 23%. Going forward, assuming the continuation of reasonably supportive rate treatment, we expect that Duke Energy Progress will maintain a CFO pre-W/C to debt ratio at or above the lower end of the range of 22% to 30% indicated for a score of "A" on this factor in our Regulated Electric and Gas Utility rating methodology.

Capital expenditures are expected to remain elevated for additional maintenance, new generation, coal ash basin remediation, and for T&D system upgrades

Annual capital expenditures at Duke Energy Progress increased meaningfully in 2015 and have remained elevated, at about $1.7 billion per year, through 2017. The increase was due in part to additional maintenance expenditures associated with the $1.2 billion acquisition of the NCEMPA generation assets in July 2015. Going forward, expenditures are expected to increase to around $2 billion per year.

In addition to higher maintenance spending, most of the additional investment can be attributed to new generation requirements, T&D system upgrades, grid modernization and coal ash basin remediation costs. Payments for coal ash related asset retirement obligations have risen from zero in 2014, to $109 million in 2015, and about $200 million in each of 2016 and 2017. For the next few years, we anticipate environmental spending, inclusive of coal ash remediation, will remain above $200 million per year. Maintenance capital expenditures, which were approximately $830 million in 2015, are projected to moderate somewhat to around $500 million per year.

In November 2015, Duke Energy Progress also announced a revised $1.1 billion plan to modernize its Western Carolinas energy system. The project includes the retirement of the Asheville coal plant, the construction of two natural gas plants, as well as upgrades to existing transmission lines and substations and the addition of solar generation and battery storage. The plan is envisioned to occur over seven years and requires various approvals, including regulatory approvals in North Carolina. In March 2016, the NCUC granted a certificate for convenience and necessity (CPCN) for a portion of the project, including the new combined cycle plants, and indicated the company could refile for the remainder of the plan at a later date. In March 2017, Duke Energy Progress filed an annual progress report on construction of the combined cycle plants with an estimated cost of $893 million. Construction is underway, with an expected in-service date in late 2019.

The utility is expected to issue debt to finance a portion of these capital expenditures, increasing leverage metrics and potentially putting pressure on cash flow coverage metrics.

Continued regulatory lag in the recovery of coal ash spending will maintain some negative pressure on coverage metrics

Duke Energy Progress is continuing to manage through the repercussions of a February 2014 storm water pipe break beneath a coal ash basin at one of Duke Energy Carolinas' retired power plants. The break resulted in the spill of 30,000-39,000 tons of coal ash into the Dan River and has subjected all of Duke's North Carolina coal ash storage basins to scrutiny.

In 2014, North Carolina lawmakers overwhelmingly passed the Coal Ash Management Act of 2014, which regulates and requires the closure of coal ash basins at all coal plant sites throughout the state. The legislation requires Duke to take costly, immediate action to excavate and close ash basins at three of its highest risk sites (including two Duke Energy Progress plants) by August 2019 and a fourth by August 2022. The 2014 legislation also required the evaluation and classification of all of the remaining basins, many of which were initially determined to be of "intermediate" priority, which would have required closure by 2024.

In July 2016, new legislation was passed that requires Duke to provide permanent alternative water supplies to neighbors within a half mile of its coal plants, but importantly also mandates the reclassification of certain intermediate priority sites as low priority once alternative water supplies are in place and certain dam enhancement projects are complete. This will expand the options for closing these basins and extends the time frame for closure to 2029.

In 2014, Duke recognized a $3.5 billion Asset Retirement Obligation (ARO) for its estimated obligations to close its North Carolina coal ash basins, including approximately $1.8 billion at Duke Energy Progress. In the second quarter of 2015, after publication of the EPA's final Coal Combustion Rules, Duke incrementally increased the ARO by $1 billion as it created additional obligations for the company in South Carolina, Indiana, and Kentucky, putting its total ARO at $4.5 billion. Duke continues to refine its estimated obligations as work continues on the sites. As of December 31, 2017, Duke had spent approximately $1.35 billion, including $500 million at Duke Energy Progress, and its total ARO remains at approximately $4.5 billion, including $2.1 billion at Duke Energy Progress.

Duke Energy Progress' coal ash basin closure and remediation spending is not recovered via trackers or other automatic cost recovery provisions and must be recovered via base rate case filings. As result, there will likely continue to be regulatory lag in the recovery of these costs. In Duke Energy Progress' most recent rate case in South Carolina, the company received approval to recover coal ash related expenses incurred from January 2015 through June 2016 over 15 years (the utility was also allowed to earn a return on the deferred asset). In North Carolina, $232 million of costs incurred through mid-2017 were approved for recovery over five years with a return at Duke Energy Progress' weighted average cost of capital. Both jurisdictions approved continued deferral of ongoing costs.

Liquidity analysis

Duke Energy Progress maintains an adequate liquidity profile. For the year ended December 31, 2017, Duke Energy Progress generated approximately $1.2 billion of cash from operations (CFO), invested approximately $1.7 billion in capital expenditures and distributed $124 million in dividend payments, resulting in negative free cash flow (FCF) of approximately $645 million. In 2016, Duke Progress generated approximately $1.9 billion of CFO, invested approximately $1.7 billion in capital expenditures and distributed $300 million in dividend payments, resulting in negative FCF of approximately $100 million. In 2018, we expect Duke Energy Progress to remain cash flow negative and that shortfalls will continue to be funded via a combination of internal and external sources.

Duke Energy Progress' additional liquidity sources include its access to funding from the Duke parent company's commercial paper program through the Duke system money pool, and from direct borrowings from the money pool. As of December 31, 2017, the utility also has $1.25 billion of direct borrowing capacity under Duke Energy's master five year credit facility, of which $684 million was available. Under a 2015 plea agreement with the U.S. Department of Justice, Duke Energy Progress is required to maintain $250 million of available capacity under the master credit facility related to violations at North Carolina facilities with ash basins. In January 2018, Duke extended a majority ($7.65 billion) of its $8.0 billion master credit facility by one year to March 2023. Duke's master credit facility does not contain a material adverse change clause for new borrowings. The facility contains a single financial covenant requiring Duke Energy and its utility subsidiaries to maintain a consolidated debt to capitalization ratio of no more that 65%, except for Piedmont Natural Gas Company (Piedmont). The debt to capital covenant level for Piedmont is 70%. As of December 31, 2017, each company was reported to be in compliance with this covenant.

Duke Energy Progress' next long-term debt maturity is $600 million of first mortgage bonds due in January 2019.

Rating methodology and scorecard factors

Exhibit 3

Rating Factors				
Duke Energy Progress, LLC				
Regulated Electric and Gas Utilities Industry Grid [1][2]	Current FY 12/31/2017		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	A	A	A	A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.2x	Aa	6.6x - 7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	20.6%	Baa	21% - 23%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	18.8%	A	18% - 20%	A
d) Debt / Capitalization (3 Year Avg)	42.9%	A	42% - 46%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching				
a) Indicated Rating from Grid		A2		A2
b) Actual Rating Assigned		(P)A2		(P)A2

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2]As of 12/31/2017
[3]This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Appendix

Exhibit 4

Cash flow and credit measures[1]

CF Metrics	2013	2014	2015	2016	2017
FFO	**1,673**	**1,770**	**1,658**	**1,602**	**1,826**
+/- Other	(109)	27	(149)	(151)	(71)
CFO Pre-W/C	**1,564**	**1,797**	**1,509**	**1,451**	**1,755**
+/- ΔWC	(221)	(412)	216	516	(524)
CFO	**1,343**	**1,385**	**1,725**	**1,967**	**1,231**
- Div	-	225	-	300	124
- Capex	1,679	1,381	1,778	1,765	1,751
FCF	**(336)**	**(221)**	**(53)**	**(98)**	**(644)**
(CFO Pre-W/C) / Debt	**26.6%**	**26.2%**	**21.0%**	**18.9%**	**22.0%**
(CFO Pre-W/C - Dividends) / Debt	**26.6%**	**23.0%**	**21.0%**	**15.0%**	**20.5%**
FFO / Debt	**28.4%**	**25.8%**	**23.0%**	**20.9%**	**22.9%**
RCF / Debt	**28.4%**	**22.6%**	**23.0%**	**17.0%**	**21.3%**

[1]All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months.
Source: Moody's Financial Metrics

Exhibit 5

Peer comparison table[1]

	Duke Energy Progress, LLC (P)A2 Stable			South Carolina Electric & Gas Company Baa3 Rating(s) Under Review			Duke Energy Carolinas, LLC A1 Stable			Georgia Power Company A3 Negative			Virginia Electric and Power Company A2 Stable		
(in US millions)	FYE Dec-15	FYE Dec-16	FYE Dec-17	FYE Dec-15	FYE Dec-16	FYE Dec-17	FYE Dec-15	FYE Dec-16	FYE Dec-17	FYE Dec-15	FYE Dec-16	LTM Sep-17	FYE Dec-15	FYE Dec-16	LTM Sep-17
Revenue	5,290	5,277	5,129	2,930	2,986	3,070	7,229	7,322	7,302	8,326	8,383	8,188	7,622	7,588	7,443
CFO Pre-W/C	1,509	1,451	1,755	804	1,138	1,228	2,541	2,627	2,573	2,745	2,429	2,275	2,561	2,936	2,920
Total Debt	7,200	7,662	7,975	5,272	6,117	5,515	8,608	9,862	10,463	11,154	11,500	12,695	12,239	12,155	12,933
(CFO Pre-W/C + Interest) / Interest Exp	6.5x	5.9x	6.3x	4.0x	4.9x	5.2x	6.6x	6.6x	6.4x	8.1x	6.9x	6.3x	5.9x	6.4x	6.0x
(CFO Pre-W/C) / Debt	21.0%	18.9%	22.0%	15.3%	18.6%	22.3%	29.5%	26.6%	24.6%	24.6%	21.1%	17.9%	20.9%	24.2%	22.6%
(CFO Pre-W/C - Dividends) / Debt	21.0%	15.0%	20.5%	9.9%	13.7%	16.5%	24.9%	6.4%	18.6%	15.4%	9.8%	7.8%	16.9%	24.2%	13.3%
Debt / Book Capitalization	41.8%	41.9%	45.0%	43.5%	45.4%	47.4%	32.8%	36.4%	41.6%	40.4%	39.7%	40.7%	44.6%	41.9%	43.0%

[1]All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade.
Source: Moody's Financial Metrics

Ratings

Exhibit 6

Category	Moody's Rating
DUKE ENERGY PROGRESS, LLC	
Outlook	Stable
Issuer Rating	A2
First Mortgage Bonds	Aa3
Senior Secured Shelf	(P)Aa3
Senior Unsecured Shelf	(P)A2
ULT PARENT: DUKE ENERGY CORPORATION	
Outlook	Negative
Issuer Rating	Baa1
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured	Baa1
Jr Subordinate	Baa2
Commercial Paper	P-2
PARENT: PROGRESS ENERGY, INC.	
Outlook	Stable
Senior Unsecured	Baa2

Source: Moody's Investors Service

REPORT NUMBER 1116766

MOODY'S
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MOODY'S INVESTORS SERVICE

CREDIT OPINION
26 April 2018

Update

Rate this Research

Edison International

Update following negative outlook

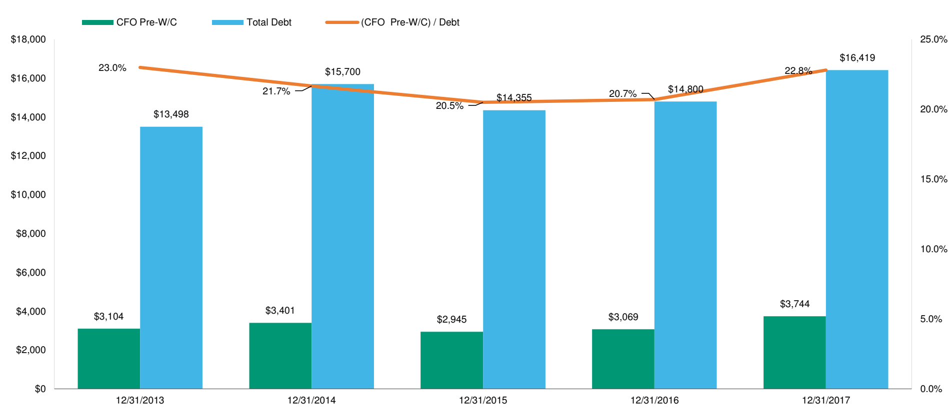
Summary

EIX's credit profile primarily reflects the credit profile of its utility subsidiary Southern California Edison Company (SCE, A2 negative). The credit profile of EIX and SCE are closely linked as the vast majority of EIX's cash flows are generated from SCE.

SCE's credit profile reflects its business fundamentals as a low risk regulated utility with mainly transmission and distribution (T&D) operations. The primary driver of SCE's business risk is California's regulatory environment, which has some strong positives as well as some significant negatives. On the positive side, SCE has access to an extensive suite of recovery mechanisms, including decoupling and a forward test year. SCE also benefits from an above average authorized return on equity and equity layer in the capital structure that bolsters its financial risk profile and provides a strong incentive for investment. On the negative aspects, California has a higher degree of political risk than most other jurisdictions in the US. California's utilities tend to receive a higher level of attention and scrutiny from both the media and public and issues can quickly become contentious and litigious.

EIX's financial metrics largely reflect that of SCE. The primary difference is that EIX had an additional $2,371 million of holding company-level debt as of December 2017 (16.3% of holding company-level debt to consolidated debt) and a very different tax position compared to SCE due to its access to the net operating losses accrued at its Edison Mission Energy (EME) subsidiary.

Exhibit 1
Historical CFO Pre-W/C, Total Debt and CFO Pre-W/C to Debt ($MM)



Source: Moody's Financial Metrics™

RATINGS

Edison International

Domicile	Rosemead, California, United States
Long Term Rating	A3
Type	LT Issuer Rating - Dom Curr
Outlook	Negative

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Credit strengths

» Low business risk of T&D operations

» California has extensive cost recovery mechanisms

» Financial metrics remain adequate

Credit challenges

» Exposure to wildfire and inverse condemnation risk

» Weakening regulatory supportiveness

» California is characterized by elevated political sensitivity

Rating outlook

SCE and EIX's negative outlook reflects the combination of falling cash flow to debt metrics as well as the heightened business risk related to the inverse condemnation exposure created by wildfires.

Factors that could lead to an upgrade

Assuming the relative amount of debt between EIX and SCE stay the same, an upgrade of SCE would lead to a corresponding upgrade of EIX.

An upgrade for SCE is unlikely until the inverse condemnation exposure from wildfires is substantially mitigated. Should inverse condemnation exposure no longer exist, we may consider an upgrade or positive outlook if SCE's CFO Pre-WC to debt ratio rises to high 20% and its CFO Pre-WC less dividends to debt ratio exceeds 25% for a sustained period of time.

Factors that could lead to a downgrade

A downgrade of SCE will result in a corresponding downgrade of EIX. A SCE ratings downgrade could occur should SCE's CFO pre-WC to debt ratio fall below 24% on a sustained basis. We may take a negative rating action on SCE if SCE is found to be liable for wildfire damages in the billions of dollars or if California policymakers failed to make sufficient progress on addressing the inverse condemnation risk before the end of this year's legislative session in August.

Key indicators

Exhibit 2

Edison International Indicators

	Dec-13	Dec-14	Dec-15	Dec-16	Dec-17
CFO pre-WC + Interest / Interest	5.2x	5.8x	5.3x	5.5x	6.1x
CFO pre-WC / Debt	23.0%	21.7%	20.5%	20.7%	22.8%
CFO pre-WC – Dividends / Debt	19.7%	18.7%	16.3%	16.1%	18.1%
Debt / Capitalization	44.0%	46.9%	42.3%	41.2%	48.9%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Profile

Headquartered in Rosemead, California, Edison International (EIX; A3 negative) is a California based electric utility holding company with its main subsidiary Southern California Edison (SCE; A2 negative) supplying electric energy to 15 million people in central, coastal and southern California. SCE is predominantly a transmission and distribution company. SCE's earnings are regulated by California Public Utility Commission (CPUC) and the Federal Energy Regulatory Commission (FERC).

Detailed credit considerations

» ELEVATED POLITICAL SENSITIVITY

We view California as having a higher degree of political sensitivity than most of the jurisdictions in the US. California's utilities tend to receive a higher level of attention and scrutiny from both the media and public and issues can quickly become contentious and litigious. In May 2016, the California Public Utility Commission (CPUC) reopened the company's settlement agreement with the interveners on the cost recovery associated with the retirement of the San Onofre Nuclear Generating Station. The settlement, which was previously approved by the CPUC, was reopened due to concerns raised by interveners that there were private communications between a company executive and a CPUC Commissioner that undermined the transparency of the negotiation process. In January 2018, SCE re-settled the case and took an additional $716 million pretax charge related to the early retirement of the SONGS, after having taken $718 million of pretax charges in 2013 and 2014. While the company is at fault regarding the communication disclosure, the amount of penalty appears disproportionate.

» WEAKENING REGULATORY SUPPORTIVENESS

As a component of longer term climate change risks, wildfire events have become a significant concern for all of California's utilities, regardless of whether they are investor or publicly owned, including SCE. Wildfires have become more frequent and more damaging due to effects of climate change, including more severe and prolonged droughts and stronger winds. In addition, California has witnessed a proliferation of real estate developments in fire-prone areas.

We still see California regulation as credit supportive for utilities, but overall the supportiveness has weakened. The rising risk associated with the wildfires and other severe weather events have translated into higher regulatory risk for investor-owned utilities in California due to inverse condemnation exposure and the uncertainty that they will be able to recover related costs from ratepayers, as evidenced by the SDG&E's disallowance in its 2007 wildfire case. For years, the California legal system has applied a legal theory of inverse condemnation to wildfire cases. This exposes a utility to liabilities from property damage claims if their equipment is determined to be the source of the fire, regardless of fault. This application of strict liability subjects Californian electric utilities to material contingent liabilities related to wildfires, a unique risk factor across the sector.

In December 2017, SCE's service territory experienced several wildfires. According to California Department of Insurance, insurers have received $1.77 billion of claims for the December 2017 wildfires and $422 million of claims for the Montecito Mudslides, which were partly caused by the December 2017 wildfires. SCE's exposure is unclear at this point, but if SCE equipment is found to be the source of the December 2017 wildfires, SCE could be liable for the wildfire claims and mudslides. SCE may offset its liability with its $1 billion insurance coverage and seek recovery from ratepayers for amounts in excess of the insurance coverage.

» DEMANDING PUBLIC POLICY GOALS

California places a lot of demands on its utilities, including many ambitious public policy initiatives that are implemented through utility operations. While these initiatives may present investment opportunities for the utilities, it also exposes them to the potential for under-recovery. Total capital expenditures for SCE were $3.8 billion in 2017 and, according to the company's latest presentation, would reach $4.2 billion in 2018, $4.8 billion in 2019 and $4.7 billion in 2020. While the regulatory recovery process appears sound, these expenditures still represent a large sum of investment spending.

There is also the potential negative impact of such initiatives on retail rates and grid reliability. The most important driver is the state's Renewable Portfolio Standard that requires investor-owned utilities to procure 50% of their total energy sales from renewables by 2030. There are also heavy costs associated with the related infrastructure such as grid upgrades and flexible generation that is needed to accommodate these new renewable resources; however, much of these cost increases have thus far been more tolerable due to the benign natural gas price environment. Furthermore, we believe the potential for natural gas prices or wholesale power prices to jump on a sustained basis is low.

» EXTENSIVE COST RECOVERY MECHANISMS

California has a robust set of cost recovery mechanisms - including a decoupling mechanism, procurement cost pass-throughs and an automatic adjustment mechanism for authorized return on equity. California does not allow utilities to earn a return on construction work in progress nor does it provide automatic recognition of investments made between rate cases but it does allow for multiple forward test years using attrition rate increases, which is also very effective in reducing regulatory lag.

In California, the authorized return on equity is established in an annual proceeding outside of the General Rate Case. In the last proceeding, SCE's was authorized a 10.3% return on equity (ROE) for 2018, which is down from 10.45% approved in the previous proceeding. The authorized ROE remains substantially above the industry of about 9.6%, which we consider to be credit supportive.

» **ADEQUATE FINANCIAL METRICS**

Historically, EIX generated a ratio of CFO pre-WC to debt in the low-20% range - 20.7% and 22.8% in 2016 and 2017, respectively - and will be around 20% going forward. Tax reform will only have a minor effect on EIX's cash flows because EIX, unlike SCE, will have net operating losses that can be used to offset tax liabilities.

We do not know if SCE would be held liable for wildfire damages or how the liability will be financed. However, as an indication of the potential impact, a $2 billion of additional debt would drive SCE's CFO pre-WC to the high teens, and EIX, to mid-teens.

At the parent holding company, EIX's long-term debt is comprised of $1.75 billion of senior unsecured notes. SCE has about $11 billion of first mortgage bonds, pollution control bonds and senior notes, as well as $2.245 billion of preferred shares. The vast majority ($2.13 billion out of $2.245 billion) of the preferred shares are structured preferred and we have accorded them with a 50% equity credit.

At the end of 2017, EIX's holding company debt comprises about 16.3% of consolidated debt but will decline to 11.5% by the end of 2018. This level of holding company debt to consolidated debt is consistent with other utility companies in the US with a one-notch separation between the rating at the holding company versus the rating.

Liquidity analysis

EIX and SCE have comfortable liquidity, as indicated by their commercial paper ratings of P-2 and P-1, respectively. For year 2017, SCE generated a negative free cash flow of $712 million and EIX, a negative $1 billion on a consolidated basis. This trend is expected to continue due to its large capital expenditure program and a growing dividend.

Despite the large negative free cash flow forecast, SCE and EIX have a healthy level of liquidity based on a total of $4 billion of revolving credit facilities ($2.75 billion at SCE and $1.25 billion at EIX) that mature in July 2022. These facilities were heavily used towards the end of 2017 but we expect them to only have minor usage going forward.

The credit facilities are not subject to a MAC representation. The debt covenant in SCE and EIX's credit facility limit their debt to total capitalization ratio to less than or equal to 0.65 to 1. At the end of 2017, SCE's debt to total capitalization ratio was 0.45 to 1, and EIX, 0.51 to 1.

Upcoming debt maturities include a $400 million first mortgage bonds at SCE due in August 2018 and $400m senior notes at EIX due April 2020.

Rating methodology and scorecard factors

Exhibit 3

Rating Factors				
Edison International				
Regulated Electric and Gas Utilities Industry Grid [1][2]	Current FY 12/31/2017		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	Baa	Baa
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	5.1x	A	5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	19.3%	Baa	19% - 21%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	15.5%	Baa	13% - 15%	Baa
d) Debt / Capitalization (3 Year Avg)	47.0%	Baa	44% - 46%	Baa
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	-1	-1	-1	-1
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		A3		A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 12/31/2017; Source: Moody's Financial Metrics™
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics™

Appendix

Exhibit 4
Cash Flow and Credit Measures [1]

CF Metrics	2013	2014	2015	2016	2017
As Adjusted					
FFO	**3,513**	**3,726**	**3,611**	**3,725**	**3,909**
+/- Other	(409)	(325)	(666)	(656)	(165)
CFO Pre-W/C	**3,104**	**3,401**	**2,945**	**3,069**	**3,744**
+/- ΔWC	(178)	(150)	1,543	360	29
CFO	**2,926**	**3,251**	**4,488**	**3,429**	**3,773**
- Div	441	462	604	688	770
- Capex	3,629	3,985	4,260	3,790	3,879
FCF	**(1,144)**	**(1,196)**	**(376)**	**(1,048)**	**(876)**
(CFO Pre-W/C) / Debt	23.0%	21.7%	20.5%	20.7%	22.8%
(CFO Pre-W/C - Dividends) / Debt	19.7%	18.7%	16.3%	16.1%	18.1%
FFO / Debt	26.0%	23.7%	25.2%	25.2%	23.8%

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months.
Source: Moody's Financial Metrics™

Exhibit 5
Peer Comparison [1]
($ in Millions)

	Edison International A3 Negative			Sempra Energy Baa1 Negative			PG&E Corporation Baa1 Negative		
(in US millions)	FYE Dec-15	FYE Dec-16	FYE Dec-17	FYE Dec-15	FYE Dec-16	FYE Dec-17	FYE Dec-15	FYE Dec-16	FYE Dec-17
Revenue	11,524	11,869	12,320	10,231	10,183	11,207	16,833	17,666	17,135
CFO Pre-W/C	2,945	3,069	3,744	2,168	2,309	3,608	4,408	5,689	6,083
Total Debt	14,355	14,800	16,419	16,429	18,959	21,331	20,102	21,465	21,713
(CFO Pre-W/C) / Debt	20.5%	20.7%	22.8%	13.2%	12.2%	16.9%	21.9%	26.5%	28.0%
(CFO Pre-W/C - Dividends) / Debt	16.3%	16.1%	18.1%	8.9%	8.2%	12.8%	17.7%	22.3%	23.4%
Debt / Book Capitalization	42.3%	41.2%	48.9%	51.4%	50.3%	54.7%	44.0%	43.4%	46.6%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade.
Source: Moody's Financial Metrics™

Ratings

Exhibit 6

Category	Moody's Rating
EDISON INTERNATIONAL	
Outlook	Negative
Issuer Rating	A3
Sr Unsec Bank Credit Facility	A3
Senior Unsecured	A3
Commercial Paper	P-2
SOUTHERN CALIFORNIA EDISON COMPANY	

Outlook	Negative
Issuer Rating	A2
Bkd LT IRB/PC	A2
Senior Secured	Aa3
Sr Unsec Bank Credit Facility	A2
Senior Unsecured	A2
Pref. Stock	Baa1
Commercial Paper	P-1
SCE TRUST II	
Outlook	Stable
BACKED Pref. Stock	Baa1
SCE TRUST IV	
Outlook	Stable
BACKED Pref. Stock	Baa1
SCE TRUST V	
Outlook	Stable
Preference Stock	Baa1
SCE TRUST III	
Outlook	Stable
Pref. Stock	Baa1

Source: Moody's Investors Service

REPORT NUMBER 1119421

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
16 June 2017

Update

Rate this Research

RATINGS

Eversource Energy

Domicile	United States
Long Term Rating	Baa1
Type	LT Issuer Rating
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

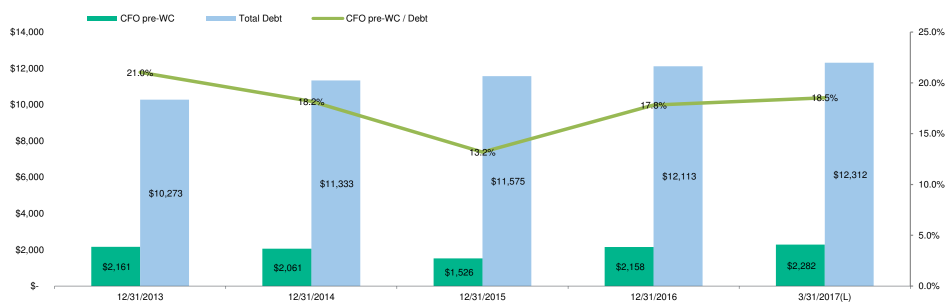
Eversource Energy

Regulated utility holding company in New England

Summary Rating Rationale

Eversource Energy's (Eversource) Baa1 rating reflects the holding company's diverse group of regulated utilities operating in credit supportive regulatory jurisdictions in the greater New England region. Eversource has a low-risk business profile through its transmission and distribution (T&D) utilities and limited exposure to non-regulated business activities. The rating also considers structural subordination of parent level debt compared to that of its operating subsidiaries (Eversource's holding company debt as a percentage of total consolidated debt was approximately 22% at year-end 2016) and stable financial profile, including a ratio of cash flow from operations pre-working capital (CFO pre- W/C) to debt in the mid-to-high teens range.

Exhibit 1
Historical CFO Pre-W/C, Total Debt and CFO Pre-W/C to Debt ($ in millions)



Source: Moody's Investors Service

Credit Strengths

» Diversified low-risk rate-regulated utility holding company with limited exposure to unregulated operations

» Utilities operate in credit supportive regulatory jurisdictions with increasing exposure to highly credit supportive Federal Energy Regulatory Commission (FERC) framework

» Financial metrics expected to remain relatively stable but could moderately weaken temporarily during construction of NPT

Credit Challenges

» Continued execution of substantial capital expenditure program will require additional debt financing

» Section 206 New England ISO complaint, although under appeal, expected to result in lower ROEs compared to historical returns

» Increase in parent level debt could widen structural subordination notching within family

Rating Outlook

Eversource's stable rating outlook reflects our expectation that it will continue to remain a low-risk regulated utility holding company and maintain financial metrics that are commensurate with its Baa1 rating, including a ratio of CFO pre-W/C to debt in the mid-to-high teens range. The stable outlook also assumes that the group's exposure to its non-regulated businesses remain limited and the level of parent-company debt will remain less than 25% of consolidated debt. The stable outlook also considers our expectation that Eversource's operating utilities, particularly the largest ones, will continue to be well positioned within their respective rating categories and supported by a constructive regulatory environments.

Factors that Could Lead to an Upgrade

Eversource's rating could be upgraded if we continued to view its regulatory environments as credit supportive and its consolidated financial metrics continued to improve, including its ratio of CFO pre-W/C to debt approaching the 20% range on a sustainable basis. Eversource's rating could also be upgraded if the ratings of its largest subsidiaries were to be upgraded.

Factors that Could Lead to a Downgrade

Eversource's rating could experience downward rating pressure if the ratings of any of its largest subsidiaries are downgraded. A rating downgrade could also occur if Eversource experienced deterioration in its consolidated financial metrics, such that consolidated CFO pre-W/C to debt declined below 14% on a sustained basis.

Key Indicators

Exhibit 2

KEY INDICATORS [1]
Eversource Energy

	12/31/2013	12/31/2014	12/31/2015	12/31/2016	3/31/2017(L)
CFO pre-WC + Interest / Interest	6.4x	6.2x	4.6x	5.9x	6.1x
CFO pre-WC / Debt	21.0%	18.2%	13.2%	17.8%	18.5%
CFO pre-WC – Dividends / Debt	16.5%	14.0%	8.6%	13.1%	13.8%
Debt / Capitalization	42.8%	43.9%	42.7%	42.6%	42.5%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Source: Moody's Financial Metrics™

Detailed Rating Considerations

UTILITIES OPERATE IN CREDIT SUPPORTIVE STATE AND FEDERAL REGULATORY JURISDICTIONS

We view the regulatory frameworks in which the group's utilities operate as credit supportive. In addition, Eversource's growing transmission business, which currently accounts for about 36% of the group's rate base, operates under the purview of the FERC, which we view as a more credit supportive regulatory framework than most state jurisdictions. Eversource's increasing exposure to FERC regulated low-risk transmission operations amid the group's substantial planned capital investments in transmission is a credit positive.

Eversource's electric distribution utilities account for about 50% of the group's rate base. Connecticut Light and Power (CL&P, Baa1 stable) is Eversource's largest electric T&D subsidiary, followed by NSTAR Electric (A2 stable), Public Service Company of New Hampshire (PSNH, A3 stable) and Western Massachusetts Electric Company (WMECO, A2 stable). Earlier this year, WMECO and NSTAR filled a merger application with the FERC with an anticipated effective date of January 1, 2018. On March 2, 2017, the FERC approved the merger application of the two entities. A second application seeking FERC approval to allow NSTAR Electric to assume WMECO's short-term debt obligation is expected to be reviewed by late-2017. The MDPU will conduct their review of the merger during NSTAR Electric and WMECO's current rate case filings.

Eversource's natural gas local distribution companies (LDCs) include Yankee Gas Services (YGS, Baa1 stable) and NSTAR Gas (not rated). These LDCs account for about 10% of consolidated rate base. The remaining approximately 4% of consolidated rate base relates to generation currently owned by PSNH, but is in the process of being divested.

We view the Massachusetts, Connecticut and New Hampshire regulatory jurisdictions as credit supportive as the state regulators allow for timely recovery of prudent operating costs and investments through the use of various decoupling and regulatory mechanisms. For example, in Massachusetts, WMECO utilizes a revenue decoupling mechanism, which reconciles the utility's distributions revenues, on an annual basis, to a baseline distribution service revenue level established by the MDPU. Decoupling insulates the utility's cash flow volatility from fluctuations in its retail electric sales, thus adding a high level of stability and predictability, a credit positive. NSTAR Electric has requested and we expect will be allowed to implement revenue decoupling in the regulators' final rate order on its rate case expected by the end of 2017 with new rates in January 2018. CL&P also utilizes a revenue decoupling mechanism in Connecticut and we expect YGS will be allowed to implement decoupling as part of its next rate case order to be filed by 2019.

Eversource's subsidiaries utilize other credit supportive regulatory mechanisms. WMECO and NSTAR Electric benefit from cost recovery mechanisms that true-up recovery of transmission, pension and other post-retirement benefits costs, and energy-related portion of bad debt expenses on an annual basis. WMECO and NSTAR Electric are also able to recoup the costs associated with the State's three-year energy efficiency program and the utility's purchased power costs are adjusted semi-annually through the basic service charge. Furthermore, both of its Massachusetts electric T&D utilities are able to recover restoration costs associated with major storms through a Storm Reserve Recovery Cost Adjustment rate mechanism, but theses cost recoveries are subject to MDPU approval, and may be less timely than in other jurisdictions.

PSNH's customer rates allow the utility to recover costs related to system upgrades and transmission services as well as costs related to energy efficiency programs and certain stranded costs on a timely basis. PSNH is also allowed to implement interim rate increases during rate case proceedings which reduces regulatory lag. Although PSNH is not currently allowed to implement revenue decoupling, the state regulators are willing to assess decoupling during utility rate case filings so the regulatory mechanism may be available to PSNH in the future. In July 2016, PSNH received approval to divest its generation fleet and will be allowed to recover its stranded costs through rate reduction securitization bonds under their 2015 Public Service Company of New Hampshire Restructuring and Rate Stabilization Agreement. The auction process for the generation assets was launched in early 2017 and the sale process is expected to be complete by the end of the year.

SUBSTANTIAL AND GROWING TRANSMISSION RATE BASE UNDER PURVIEW OF MORE CREDIT SUPPORTIVE FERC REGULATORY FRAMEWORK

At year-end 2016, Eversource's transmission rate base accounted for approximately $5.7 billion out of the group's total rate base of about $15.7 billion. FERC's regulatory framework includes premium allowed returns that are set based on a formulaic forward-looking cost of service model that adjusts for changes in network load that impacts demand. This ensures the utility's ability to earn the allowed ROE and enhances the stability and predictability of cash flows, a significant credit positive. Transmission projects generally enter rate base after they are placed in commercial operation, however certain FERC approved projects, such as the New England East-West Solution (NEEWS) projects partly constructed by WMECO, can recover construction work in progress (CWIP) costs in rate base, another credit positive.

In addition, FERC regulated returns are generally higher than most states. Eversource's utilities are allowed FERC ROEs ranging from 11.07% to 11.57% including any incentive adders. The base ROE for transmission owners in the Independent System Operator - New England (ISO-NE) region allowed by FERC is expected to be reduced compared to historical levels as a result of the Section 206 complaints filed with FERC. More discussion on this matter below.

SECTION 206 COMPLAINTS EXPECTED TO RESULT IN LOWER AUTHORIZED ROES COMPARED TO HISTORICAL RETURNS

We expect authorized ROEs for New England transmission owners including Eversource utilities to be lower compared to historical rates. However, total ROEs including incentive adders should still remain above authorized ROEs allowed in most states. In addition, we do not expect any changes to the formulaic forward-looking credit supportive ratemaking framework allowed by FERC. Four separate complaints have been filed at FERC by groups of New England state attorneys general, state regulatory commissions, consumer advocates, consumer groups, municipal parties and other parties challenge the authorized base ROE of 11.14% that had been utilized by New England transmission owners since 2005. Each complaint covers a refund period of 15 months. FERC ruled on the first ISO-NE Section 206 complaint in June 2014 and cut the authorized ROE to 10.57% from 11.14%. FERC's order also limited the total authorized ROE, including incentive adders, to 11.74%, which is the high end of the zone of reasonableness.

On April 14, 2017, the D.C. Circuit Court of Appeals, vacated and remanded the decision back to FERC. The Court of Appeals argued that FERC failed to show that the prior base ROE of 11.14% was unjust and unreasonable. Given that FERC does not currently have a quorum, the final outcome of these complaints will be further delayed. Nonetheless, we expect authorized ROEs to be reduced from the historical base rate of 11.14%.

When setting the new rate, FERC established a zone of reasonableness using a two-step discounted cash flow (DCF) methodology rather than the one-step DCF methodology which they used historically. The two-step approach includes estimates for a utility's short term growth rate and a long-term growth rate based on an average of projected GDP growth rates, which is similar to what FERC uses to decide ROEs for natural gas and oil pipeline cases.

On March 22, 2016, an administrative law judge (ALJ) recommended a base authorized ROE of 9.59% and 10.9% on the second and third complaints, respectively. A fourth complaint was filed on April 29, 2016 and no ALJ recommendation has been rendered to date. A trial date is scheduled for August 2017. Without a quorum at FERC and given that the first complaint has been remanded back to FERC, we do not expect a decision on complaints two, three and four until late 2017 or even more likely in 2018. Eversource's operating utilities involved in the complaint have reserved approximately $39.1 million for the second complaint for expected customer refunds. Of this amount, $21.4 million for CL&P, $8.5 million NSTAR Electric, $3.1 million for PSNH, and $6.1 million for WMECO related to the second complaint's refund period of December 2012 through March 2014.

CONTINUED EXECUTION OF SUBSTANTIAL CAPITAL INVESTMENTS FINANCED IN A BALANCED MANNER NEEDED TO MAINTAIN FINANCIAL METRICS

The Eversource group continues its substantial capital expenditures program. Eversource plans to grow its rate base from $15.7 billion at the end of 2016 to $19.7 billion in 2020 through investments of approximately $9.6 billion during that period, which includes approximately $5.4 billion in electric and natural gas distribution assets and $3.9 billion in electric transmission assets. On average, Eversource and its utilities will get approximately 60% of immediate rate recovery from its investments over that period, a credit positive. The planned capital investments in Eversource's distribution operations include approximately $3.6 billion for electric distribution largely for load growth and system upgrades. The remaining approximately $1.5 billion is planned for its natural gas distribution companies, where its LDCs expect to continue the group's natural gas expansion and fuel-conversion opportunities in both Connecticut (YGS) and Massachusetts (NSTAR Gas).

The group continues to invest heavily in the more credit supportive FERC regulated transmission infrastructure, a credit positive. Eversource's planned $3.9 billion transmission investments include $1.6 billion related to the Northern Pass transmission project. The Northern Pass project will be constructed, owned and operated by Eversource's Northern Pass Transmission, LLC (NPT) subsidiary.

Northern Pass is a high-voltage direct-current bi-directional transmission line that will interconnect Quebec with Franklin, NH and an associated alternating current radial transmission line connecting Franklin with Deerfield, NH. Under the terms of the FERC approved Transmission Service Agreement (TSA), NPT will charge cost-based rates and sell 1,200MW of firm electric transmission rights over a term of 40 years to Hydro Renewable Energy, a subsidiary of Hydro Quebec (Aa2 stable) to bring Canadian sourced hydro-power into New England. NPT's capital structure is expected to consist of balanced mix of 50% equity and 50% debt. Under the terms of the TSA, NPT's ROE will have an ROE of 12.56% during construction, and the prevailing ISO-NE regional base rate ROEs once in service, which is currently a base ROE of 10.57% but is under appeal and has been remanded back to FERC (see further discussion above). However, unlike the New England East-West Solution (NEEWS) project, in part developed by CL&P and WMECO, NPT will not recover CWIP in rates, but will record non-cash Allowance for Funds Used during Construction (AFUDC) earnings.

The project attained ISO-NE approval in 2013 and in July 2015, the Department of Energy (DOE) issued its draft Environmental Impact Statement (EIS) which was another key milestone in the permitting process. The final EIS is expected to be issued by the DOE by the third quarter of 2017. The New Hampshire Site Evaluation Committee accepted NPT's application as complete which allowed for the state's siting process to move forward. Eversource expects to obtain the NH siting approval by September 30,-2017. The Presidential Permit from the DOE is expected by the end of 2017 after the siting approval is granted, which will then allow construction to begin. The company expects the transmission line to be in-service in late-2019. Delays have pushed out planned investments with the heavy investment years now planned during 2018 and 2019. Further delays could occur. In August 2016, Massachusetts enacted clean energy legislation that requires the state utilities to jointly solicit proposals and enter into long-term contracts for clean energy, such as hydropower. The request for proposal (RFP) was issued on March 31, 2017, and Northern Pass is expected to bid into the RFP in late July 2017. Assuming that Eversource will finance this project with a balance mix of equity and debt and given that NPT will operate under a FERC approved transmission service agreement, we expect the project to enhance Eversource's credit profile over the longer term.

Not included in the planned capex discussed above is Eversource's participation in the Access Northeast pipeline and storage project, which is a partnership with Enbridge Inc. (Baa2 negative) and National Grid Plc (Baa1 stable). Eversource and Enbridge's ownership interest in the project is 40%, while National Grid's ownership is 20%. The approximately $3 billion brownfield project (Eversource's current share is $1.2 billion) will increase the capacity of Enbridge's existing natural gas pipeline capacity by about 900 million cubic feet per day while also enhancing the Algonquin and Maritimes Northeast pipeline systems. The partners also expect that this project will improve the reliability of the regional power generation system during peak demand periods, particularly during extreme weather conditions such as those resulting from the Polar Vortex in the winter of 2014. The non-binding open season was completed in early 2015. The project is subject to FERC and other federal and state regulatory approvals. Multiple states currently will not allow end user customers to be billed via a surcharge on monthly bills to help recover some of the costs to build the pipeline. As such, Eversource and the other co-owners, are currently evaluating its options regarding Access Northeast, including the potential for changes to state infrastructure legislation and contracts with gas distribution utilities, in order to allow the pipeline to be built and enable cost recovery. As a result, the final cost and expected in-service date of the pipeline cannot be estimated at this time.

Eversource and its subsidiaries have exhibited a proven track record of successfully completing substantial projects on time and within budget in the past. Successful execution of these projects going forward using a balanced mix of equity and debt will be necessary to maintain the group's current financial profile. Given the heavy involvement of several regulatory and governmental agencies in many of these projects further delays may occur.

STRUCTURAL SUBORDINATION OF PARENT LEVEL DEBT

Eversource rating reflects the structural subordination of its parent level debt-holders relative to the indebtedness of its operating utilities. Eversource's rating also incorporates the benefits associated with the regulatory and geographic diversification from owning six regulated utilities within the greater New England region.

About half of the group's consolidated rate base is represented by operating utilities with an issuer rating of Baa1, including its largest subsidiary, CL&P. Approximately a third of Eversource's rate base, which includes NSTAR Electric and WMECO, are rated A2 and the majority of the remaining rate base relates to PSNH's rate base, is rated A3. The remaining portion includes NSTAR Gas and NPT, both of which are not rated. The increased investment to grow its FERC regulated transmission rate base has strengthened the group's credit profile because of the highly credit supportive FERC regulatory framework.

As of December 31, 2016, Eversource's parent level debt of $2.0 billion represented approximately 22% of the group's consolidated indebtedness. Additional debt anticipated from the financing of the Aquarion acquisition will move parent level debt closer to 25%. As parent level debt tends to exceed 25% of consolidated indebtedness it often leads to wider notching differential between the ratings of the parent and its operating subsidiaries.

FINANCIAL METRICS EXPECTED TO REMAIN RELATIVELY STABLE ALTHOUGH COULD WEAKEN TEMPORARILY DURING CONSTRUCTION OF NPT

Going forward, we expect Eversource's consolidated financial metrics to remain stable because of management's prudent cost management, timely recovery of the majority of its annual investments and the financing of these investments in a balanced manner of debt and equity. Over the next two years, we expect Eversource's consolidated CFO pre-W/C to debt to remain in the mid-to-high teens range and RCF to debt to remain in the low-teens range.

Eversource's financial metrics could moderately weaken, at least temporarily, if NPT is approved and construction begins in early 2018. As NPT is being constructed over the expected two-year period, we would expect Eversource's financial metrics to weaken slightly such that its ratio of CFO pre-W/C to debt remains in the mid-teens range. We would expect the decline in metrics to only be temporary Eversource issuers debt to finance the construction of the transmission line, but not realize the associated cash flow generation from the line until the line goes into service expected in early 2019. Over the long-term, if Eversource is successful in the execution of its significant non-utility projects, such as NPT and Access Northeast, and assuming the projects are financed with a balanced mix of equity and debt, Eversource has potential to further strengthen its financial metrics. For the twelve months ended March 31, 2017, Eversource's CFO pre-W/C to debt was 18.5% while its RCF to debt was 13.8%

Liquidity Analysis

Eversource's Prime-2 short-term commercial paper rating reflects the company's adequate liquidity profile, which is principally supported by the upstream dividends from its diversified group of regulated utilities. Consistent with historical years, Eversource maintains a modest consolidated cash balance of $46 million as of March 31, 2017.

Eversource and all of its subsidiaries (CL&P, NSTAR Gas, PSNH, Yankee Gas and WMECO) excluding NSTAR Electric utilize a $1.45 billion revolving joint credit facility that expires in September 2021. Under the revolving credit facility, CL&P has a borrowing sublimit of $600 million, and PSNH and WMECO each have borrowing sublimits of $300 million. Borrowings under this facility are not subject to any material adverse change clause, but there is one financial covenant that sets a maximum total debt to total capitalization of 65%. Eversource and its subsidiaries were in compliance as of March 31, 2017. Eversource uses this joint facility to back-stop its same sized commercial paper program. Eversource has typically used its short-term borrowings to help fund the subsidiaries' capex programs, pension contributions, working capital requirements (including any storm related costs) and/or debt repayments until longer term financing is arranged. At March 31, 2017, approximately $649 million was available on the revolver. As of March 31, 2017, there were intercompany loans from Eversource of $3.4 million to CL&P, $144.9 million to PSNH and $71.4 million to WMECO.

NSTAR Electric has its own $450 million senior unsecured committed revolving credit facility that expires in September 2021. The revolver backstops NSTAR Electric's $450 million commercial paper program. At March 31, 2017, NSTAR Electric had $275.5 million available on its revolving credit facility. NSTAR Electric has typically used short-term borrowings to fund capital needs until longer term financing is arranged. Borrowings on the facility are not subject to any material adverse change clause, and NSTAR Electric has sufficient cushion on its only financial maintenance covenant of a maximum total consolidated debt to capitalization of no more than 65%.

Eversource's main source of cash flow generation is the dividend distributions from its subsidiaries which totaled about $725 million in 2016, which was more than Eversource's shareholder dividend distributions of $564 million for the year. The dividend distributions by subsidiary in 2016 included the following: CL&P ($200 million), NSTAR Electric ($278 million), PSNH ($78 million), and WMECO ($38 million). Eversource's capital contributions to its subsidiaries was $590 million in 2016 including $200 million to CL&P. Eversource has about $2.0 billion of holding company debt with $450 million of senior notes scheduled to mature in 2018 and $350 million of debentures due in 2019.

We expect that Eversource will continue to fund the group's planned capital investments including $2.7 billion planned in 2017, with a mix of debt and equity, including internally generated cash flows, short-term borrowings on its revolving credit facility and long-term debt issuances. The group also estimated that its pension plan contributions for 2017 will be approximately $175 million.

Profile

Headquartered in Hartford, CT and Boston, MA, Eversource Energy is a public utility holding company of mostly regulated utilities. With a total rate base of about $15.7 billion, Eversource Energy is the largest utility system in the New England region serving more than 3.7 million electric and natural gas customers.

Eversource owns one vertically integrated utility, Public Service Company of New Hampshire (A3 stable); and three electric transmission and distribution utilities: Connecticut Light and Power (Baa1 stable), NSTAR Electric Company (A2 stable) and Western Massachusetts Electric Company (A2 stable). In addition, Eversource owns two natural gas local distribution utilities: Yankee Gas Services Company (Baa1 stable) and NSTAR Gas (not rated). Eversource also owns Eversource Energy Gas Transmission LLC (not rated) and Northern Pass Transmission LLC (not rated).

The utilities are regulated at the state level by their respective public utility commissions in Connecticut, Massachusetts, and New Hampshire, and are also subject to the Federal Energy Regulatory Commission (FERC) purview for the group's transmission businesses and PSNH's hydro-electric license conditions.

Eversource also consolidates the ownership interest held by its regulated subsidiaries in the decommissioned regional Nuclear generation companies: Connecticut Yankee Atomic Power Company (CYAPC; 63% ownership) and Yankee Atomic Electric Company (YAEC; 52.5%) while the group's 24% interest in Main Yankee Atomic Power Company (MYAPC) is recorded under the equity method. The group's remaining non-regulated businesses consist mainly of small subsidiaries including: The Rocky River Realty

Company (a real estate company), the HWP Company (formerly the Holyoke Water Power Company), and NU Enterprises. The latter is the parent company of Northeast Generation Services Company (NGS) to which it renders operation and maintenance services.

For more details about the rating considerations of Eversource's subsidiaries including their regulatory environment and credit profiles please refer to their respective Credit Opinions available on www.moodys.com

Rating Methodology and Scorecard Factors

Exhibit 3

Rating Factors				
Eversource Energy				
Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 3/31/2017		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	5.5x	A	5.3x - 5.8x	A
b) CFO pre-WC / Debt (3 Year Avg)	16.3%	Baa	15% - 18%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	11.7%	Baa	10% - 14%	Baa
d) Debt / Capitalization (3 Year Avg)	42.8%	A	41% - 45%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	-1	-1	-1	-1
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		Baa1		Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2017(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Source: Moody's Financial Metrics™

Ratings

Exhibit 4

Category	Moody's Rating
EVERSOURCE ENERGY	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1
Pref. Shelf	(P)Baa3
Commercial Paper	P-2
CONNECTICUT LIGHT AND POWER COMPANY	
Outlook	Stable
Issuer Rating	Baa1
First Mortgage Bonds	A2
Senior Secured	A2
Pref. Stock	Baa3
NSTAR ELECTRIC COMPANY	
Outlook	Stable
Issuer Rating	A2
Senior Unsecured	A2
Pref. Stock	Baa1
Commercial Paper	P-1
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Secured Shelf	(P)A1
WESTERN MASSACHUSETTS ELECTRIC COMPANY	
Outlook	Stable
Issuer Rating	A2
Senior Unsecured	A2
NSTAR LLC	
Outlook	No Outlook
Senior Unsecured	Baa1
YANKEE GAS SERVICES COMPANY	
Outlook	Stable
Issuer Rating	Baa1
First Mortgage Bonds	A2

Source: Moody's Investors Service

REPORT NUMBER 1077585

MOODY'S
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MOODY'S
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CREDIT OPINION

30 June 2017

Update

Rate this Research

RATINGS

OGE Energy Corp.

Domicile	Oklahoma City, Oklahoma, United States
Long Term Rating	A3
Type	Senior Unsecured - Dom Curr
Outlook	Negative

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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OGE Energy Corp.

Holding Company of Electric Utility and Midstream Assets

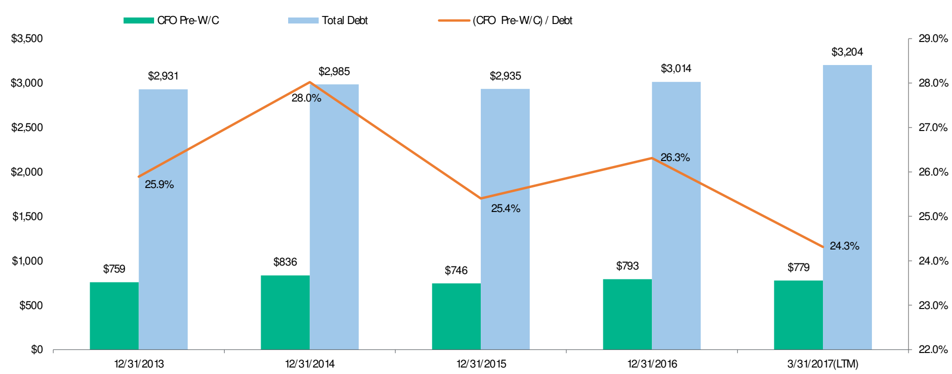
Summary Rating Rationale

OGE Energy Corporation's (OGE) A3 rating primarily reflects the credit profile of Oklahoma Gas & Electric (OG&E, A1 negative), its primary subsidiary and the largest utility in Oklahoma. OG&E's credit is underpinned by its low business risk as a regulated utility company with strong cash flow generation. OGE's negative outlook reflects the negative credit trends at OG&E, including the potential for declining financial metrics amidst some uncertainty in cost recovery and earned returns in Oklahoma.

OGE's rating also reflects the risks associated with its 50/50 general partner (GP) interest in Enable Midstream Partners, LLC (Enable, Baa3 stable) – an oil and gas gathering, processing and natural gas pipeline master limited partnership (MLP). While Enable's business risk is a qualitative negative, OGE's financial profile is still appropriate for the A3 rating category when excluding roughly $140 million in annual cash flow received from the MLP through the last twelves months (LTM) as of 31 March 2017 and when consolidating OGE's 25.7% limited partner (LP) interest in Enable.

Exhibit 1

Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt



Source: Moody's Investors Service

Credit Strengths

» Sizeable regulated utility subsidiary with a strong financial position

» Very little holding company debt provides more financial flexibility than peers

Credit Challenges

» Surprisingly negative general rate case outcome for OG&E could signal declining cost recovery and earned returns

» High dividend payout ratio

» Ownership interest in Enable adds business risk

Rating Outlook

OGE's negative outlook reflects the negative credit trends at OG&E, including the potential for declining financial metrics and some regulatory uncertainty. It also incorporates stable to improving financial performance at Enable.

Factors that Could Lead to an Upgrade

» CFO pre-WC to debt well over 25% on a sustainable basis

» RCF to debt over 20% on a sustainable basis

» Improved credit profile of Enable

Factors that Could Lead to a Downgrade

» Reduced predictability in the level of OG&E's regulatory support

» CFO pre-WC to debt nearing 20% and RCF to debt approaching 15%

» Higher-risk financial policies, such as increasing holding company debt, over 60% dividend payout, or additional unregulated asset investment

» Downgrade of Enable

Key Indicators

Exhibit 2

KEY INDICATORS [1]
OGE Energy Corp.

	12/31/2013	12/31/2014	12/31/2015	12/31/2016	3/31/2017(L)
CFO pre-WC + Interest / Interest	5.9x	6.5x	5.8x	6.1x	6.1x
CFO pre-WC / Debt	25.9%	28.0%	25.4%	26.3%	24.3%
CFO pre-WC – Dividends / Debt	20.2%	21.9%	18.4%	18.8%	17.1%
Debt / Capitalization	36.2%	35.1%	34.8%	34.3%	35.7%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Detailed Rating Considerations

RECENT RATE CASE OUTCOME REDUCES ALLOWED RETURNS AND SOME COST RECOVERY

Roughly two-thirds of OGE's business consists of OG&E's utility operations in in Oklahoma; therefore, the degree of support received from the Oklahoma Corporation Commission (OCC) is a key ratings driver for OG&E and OGE.

On 5 March 2017, the OCC issued a general rate case order that is expected to result in a declining financial profile for OG&E in 2017. The order was a negative surprise, since the OCC allowed revenue increase of $8.9 million was well below a December

2016 administrative law judge's recommendation of $40.7 million. The difference was due to a lower allowed ROE level and lower depreciation expense allowed by the OCC. Therefore, the company will have less net income and reduced depreciation recovery supporting cash flow from operations than it had previously.

Moreover, the OCC made comments in its order that it is concerned with OG&E's current equity-to-debt ratio, and that the company should evaluate adjusting its capitalization to maximize the benefits of lower cost debt in its next rate case. This, along with reduced returns and depreciation recovery, adds an overhang of uncertainty over future rate case decisions and what OG&E's ongoing financial profile will be.

We also note that the time taken to reach various regulatory decisions within the state have increased in recent years. For example, it took 15 months from filing to rate order for OG&E and 16 months for Public Service Company of Oklahoma (PSCO, Baa1 stable) for their most recent order. We do not expect this to be the ongoing trend, but it does create additional challenges in earning respective allowed returns when the delayed cost recovery is based on a historic test year (i.e., the cost structure from which revenues are based includes historical expenses).

We have typically viewed the regulatory environment in Oklahoma to be a credit positive, since OG&E has been successful in maintaining regulatory relationships with interveners and consumer advocates, which have yielded credit supportive rate case outcomes. This relationship and support has been important, since Oklahoma rate making does not include many cost tracker or rider type mechanisms that provide transparent, dependable cash recovery of certain costs.

We view the Arkansas regulatory environment to be supportive to credit, due to implementation of a formula rate plan (FRP) in 2016. The FRP offers a clear framework for timely operating and capital cost recovery and also enhances the predictability of rate case proceedings and outcomes, due to the use of a forward test year and automatic annual revenue adjustments.

FINANCIAL METRICS WILL WEAKEN NEAR-TERM, BUT REBOUND WITH OG&E RATE CASES AND ENABLE'S GROWTH

Since OG&E's financial performance and cash flow generation is the primary contributor to consolidated performance, we expect both the utility and OGE's financial profile to decline in 2017, such that cash flow from operations pre-working capital (CFO pre-WC) to debt will be in the low 20% range. However, we expect that as significant capital projects are completed, OG&E will receive timely cost recovery of its environmental expenditures and rebound to around 25% cash flow to debt.

At the same time, Enable's management has taken various credit supportive actions over the last 18 months, which supported a stable financial contribution to OGE. The MLP has weathered the 2015/2016 industry downturn by stalling dividend growth, improving contract certainty and maintaining debt/EBITDA of no worse than 4.3x - which has improved to 4.0x through LTM 1Q17. Recently announced growth projects and an improved equity market for the MLP sector also point to improved financial performance by the company over the next 12 months. This will benefit OGE's consolidated financial profile over the long-term.

When applying a proportionate consolidation approach, based on OGE's 25.7% limited partner interest, of Enable's total CFO and debt (i.e., roughly $770 million and $3.3 billion through LTM 1Q17), we believe that OGE's CFO pre-WC to debt will rebound to around 25% for the 2018/2019 time frame.

OGE IS WELL POSITIONED AT AN A3 RATING VERSUS PEER HOLDING COMPANIES

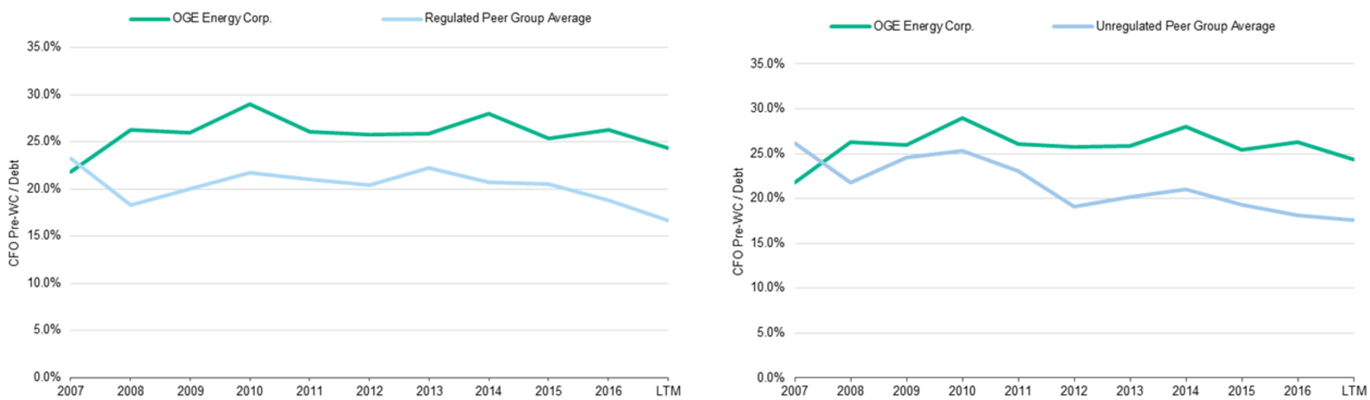
Through LTM 31 March 2017, OGE produced approximately 24% CFO pre-WC to debt, which is strong and compares well to other regional regulated utility holding companies that have averaged 17% over the same time. The regulated peers include Ameren Corporation (Baa1 stable), Duke Energy Corporation (Baa1 stable), Great Plains Energy, Inc. (Baa3 stable), The Southern Company (Baa2 stable) and Xcel Energy, Inc. (A3 stable).

Along the same lines, several diversified holding companies with unregulated operations have averaged 16% CFO pre-WC to debt through LTM March. This peer group includes companies like Entergy Corporation (Baa2 stable), Exelon Corporation (Baa2 stable), FirstEnergy Corp. (Baa3 stable), NextEra Energy, Inc. (Baa1 stable) and Sempra Energy (Baa1 stable).

Many of these companies have a wide diversity of subsidiaries, are rated Baa and have substantial holding company debt. On the contrary, OG&E makes up more than 80% of OGE's business and has a negligible amount of long-term holding company debt.

We also note that OGE's dividend payout is high at around 70% over the last two years. However, it is slightly under the regulated peers (75% average) but higher than the unregulated companies (63% average, when excluding losses related to impairments).

Exhibit 3
OGE's financial position is stronger than other select holding companies.



Source: Moody's Investors Service

OWNERSHIP OF ENABLE ADDS BUSINESS RISK

Enable's distributions represent roughly 15-20% of OGE's consolidated cash flow from operations, and is thus a material aspect of OGE's credit quality. As such, we attribute a higher business risk profile to OGE due to its MLP subsidiary.

Enable's operations are comprised of higher-risk oil and natural gas gathering and processing (representing roughly 60% of gross margin) and natural gas transmission and storage assets (representing about 40% of gross margin). While the pipeline assets are also regulated, we view these as higher risk than regulated utilities, like OG&E, given the competitive nature of the industry and Enable's relatively short average contracted life (i.e., about 3 years). Enable functions under a commodity price sensitive business model, though much of that risk is mitigated by fixed or fee-based contractual arrangements for a period of time. Currently, about 85% of Enable's gross margin is generated under such contractual terms - a credit positive.

Despite OGE's business risk profile being negatively impacted by Enable, the holding company can sustain A3-type financial metrics under various Enable-based sensitivities. For example, applying a proportionate consolidation approach under OGE's 25.7% LP interest (and no incentive distribution rights, currently) would add roughly $200 million of CFO and $850 million of adjusted debt to OGE's consolidated numbers (excluding the equity investment distributions from Enable), resulting in approximately 21% CFO to debt. Alternatively, assuming no dividends are received from Enable, OGE's CFO to debt would decline to a similar level - around 20%.

Currently, the largest uncertainty surrounding Enable is the CenterPoint Energy, Inc. (CNP, Baa1 stable) ownership review. In February 2016, CNP announced a strategic review of their Enable ownership. As part of OGE's right-of-first-offer (ROFO) in the strategic review, OGE submitted two proposals, with at least one unnamed third party, to acquire CNP's 55.4% interest. These offers have not been accepted, based on the lack of CNP response.

CNP's review is negative for OGE due to the potential effect on Enable's credit profile, since it adds uncertainty into the ultimate strategic decision making around the MLP. A change to the ownership risk profile of Enable could reduce the credit quality of the MLP and alter the dividend strategy going forward.

Liquidity Analysis

OGE is expected to be free cash flow negative in 2017, mostly due to large capital expenditures as OG&E winds down its environmental upgrades. The company's internal liquidity consists of no cash on the balance sheet at 31 March 2017, consistent with $0.3 million of cash on hand at year-end 2016. The company also generates somewhat volatile cash flow from operations, which have averaged about $740 million from 2015 - LTM 31 March 2017. Going forward, these sources compare to around an expected $500 million in consolidated capital expenditures and dividends above $250 million in 2018.

OGE's external liquidity consists of $450 million of credit facilities at both OGE and OG&E, each expiring in March 2022. The facilities may be increased under certain circumstances by $150 million each, totaling a maximum revolving commitment limit of $600 million. As of March 2017, OGE had borrowings of $128 million, while OG&E had $1.8 million outstanding under the respective credit facilities. Both facilities have same day drawing availability and financial covenants consisting of a maximum debt to capitalization ratio of 65%. As of 31 March 2017, both companies were in compliance with the covenants.

The next significant debt maturity is in July 2017 when $125 million of OG&E senior debt matures, which the company expects to refinance with $300 million of new senior notes issued in March 2017. OGE has a $100 million issuance maturing in November 2017.

Structural Considerations

We apply two notches of rating differential between OGE and its primary subsidiary, OG&E. One notch is based on the legal subordination of any debt that resides at the holding company (including short-term borrowings that is serviced by subsidiary dividends) and the other notch is due to the heightened business risk of Enable.

Currently, OGE has only one parent company note outstanding of $100 million and $128 million of revolver borrowings as of March 2017. When these amounts are compared to total consolidated debt, the $100 million is roughly 4% of consolidated long-term debt and the $228 million existing at the parent is approximately 8% of total consolidated debt. This compares favorably to most utility holding companies.

Corporate Profile

OGE Energy Corp. (OGE, A3 negative) is a publicly traded holding company that owns Oklahoma Gas & Electric (OG&E, A1 negative) as well as a 25.7% limited partner interest in portion of Enable Midstream Partners, LP (Enable, Baa3 stable).

OG&E is a wholly owned, vertically integrated regulated electric utility operating in Oklahoma and Arkansas. Enable has been a publicly-traded master limited partnership (MLP) since April 2014, with stable gas transmission pipeline assets and a more volatile gathering and processing segment. Enable's general partner interest is held by OGE Energy and CenterPoint Energy, Inc. (CNP, Baa1 stable). OGE owns a 25.7% limited partner (LP) interest and 60% economic interest in the incentive distribution rights (IDRs), while CNP owns a 53.9% LP interest and a 40% economic interest in the IDRs. The remaining LP units are held by ArcLight Capital Partners (not rated) and by the public.

Rating Methodology and Scorecard Factors

Exhibit 4

Rating Factors				
OGE Energy Corp.				
Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 3/31/2017		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Ba	Ba	Ba	Ba
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.1x	Aa	5.6x - 6x	A
b) CFO pre-WC / Debt (3 Year Avg)	25.4%	A	20% - 25%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	18.5%	A	15% - 20%	A
d) Debt / Capitalization (3 Year Avg)	35.5%	A	33% - 36%	Aa
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	-2	-2	-2	-2
a) Indicated Rating from Grid		Baa2		Baa2
b) Actual Rating Assigned		A3		A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2017(L).
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics™

Ratings

Exhibit 5

Category	Moody's Rating
OGE ENERGY CORP.	
Outlook	Negative
Sr Unsec Bank Credit Facility	A3
Senior Unsecured	A3
Commercial Paper	P-2
OKLAHOMA GAS & ELECTRIC COMPANY	
Outlook	Negative
Issuer Rating	A1
Sr Unsec Bank Credit Facility	A1
Senior Unsecured	A1
Commercial Paper	P-1

Source: Moody's Investors Service

REPORT NUMBER 1079800

MOODY'S
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MOODY'S
INVESTORS SERVICE

CREDIT OPINION
16 May 2017

Update

Rate this Research

RATINGS

Pinnacle West Capital Corporation

Domicile	United States
Long Term Rating	A3
Type	LT Issuer Rating
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

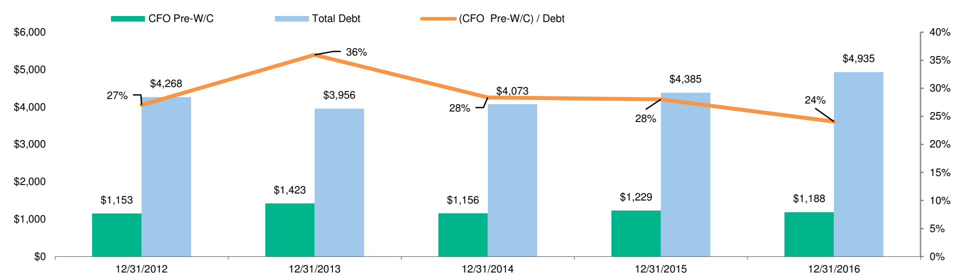
Pinnacle West Capital Corporation

Regulated Utility Holding Company and Parent of Arizona Public Service Company

Summary Rating Rationale

Pinnacle's A3 rating reflects the stable cash flows (i.e. upstream dividends) provided by its principal operating subsidiary,Arizona Public Service Company (APS, A2 stable), a regulated vertically-integrated electric utility in Arizona. Pinnacle's rating is one-notch lower than the rating of APS to reflect the structural subordination of the parent's obligations to creditors at the utility level. APS' A2 senior unsecured rating reflects the constructive Arizona regulatory environment, which allows for a broad group of timely cost and investment recovery mechanisms; solid customer and load growth in Arizona compared to the national average, and management's effective cost controls, which allows APS to earn close to its authorized ROE and drives its solid financial metrics. The A2 rating incorporates a view that APS will continue to maintain a strong financial profile, including a ratio of cash flow pre-W/C to debt in the mid-20% range. Pinnacle has only $125 million of parent company debt and a small amount of commercial paper borrowings.

Exhibit 1
Ratio of CFO pre-WC to Debt Historical Trend



Source: Moody's Investors Service

Credit Strengths

- Constructive Arizona regulatory environment including recently proposed rate case settlements that supports utility credit quality
- Cost recovery mechanisms provide timely recovery of prudent costs and investments are credit supportive
- Arizona Corporation Commission (ACC) proactively monitoring and addressing cost-shift concerns related to rooftop distributed generation through rate design changes
- Solid financial profile expected to remain stable
- Minimal parent holding company debt, which is structurally subordinated to creditors of APS' debt

Credit Challenges

- Continued growth of rooftop solar increases cost-shift burden and maintains headline risk
- Rate design changes underway, however fixed cost structure disproportionately mis-matched compared to fixed revenue charges to customers
- Meaningful, although reduced, reliance on coal generation requires further environmental capex and generation switching to meet a lower carbon future

Rating Outlook

Pinnacle's rating outlook is based on that of its principal utility subsidiary, APS. APS' stable rating outlook reflects our expectation that the regulatory environment in Arizona remains credit supportive such that the recently proposed rate case settlement is adopted by the ACC without meaningful changes that would impact the credit quality of the utility. The stable outlook incorporates our view that APS will maintain stable cash flows given the timely rate recovery mechanisms allowed by the ACC, such that APS' financial metrics will remain consistent with A2 rated US regulate utilities, including CFO pre-W/C to debt in the mid-20% range. The stable outlook also reflects APS' planned rate base expansion will receive constructive rate relief through enhanced recovery mechanisms and that planned capital expenditures will be financed in a manner that is consistent with the utility's current financial position.

Factors that Could Lead to an Upgrade

Pinnacle's rating could be upgraded if APS' rating was upgraded. APS' rating could be upgraded with continued credit supportiveness of the Arizona regulatory environment that led to meaningfully greater predictability and timely recovery of prudently incurred costs and investments; and maintenance of strong financial metrics including CFO pre-W/C to debt in the high 20% range on a sustained basis.

Factors that Could Lead to a Downgrade

Pinnacle's rating could be downgraded if Pinnacle increased its leverage or increased its overall risk profile through investments in unregulated activities. Additionally, Pinnacle's rating could be downgraded if APS' rating was downgraded. APS' rating could be downgraded if we believe the Arizona regulatory environment were to become less credit supportive or predictable such that there is an adverse rate case ruling or cost recovery disallowances; or if APS experienced prolonged operational difficulties or increased non-recoverable costs causing financial metrics to weaken such that CFO pre-W/C to debt declined below 22% on a sustained basis.

Key Indicators

Exhibit 2

	12/31/2016	12/31/2015	12/31/2014	12/31/2013	12/31/2012
CFO pre-WC + Interest / Interest	6.3x	6.8x	6.3x	7.1x	5.6x
CFO pre-WC / Debt	24.1%	28.0%	28.4%	36.0%	27.0%
CFO pre-WC – Dividends / Debt	18.5%	22.1%	22.3%	30.0%	21.7%
Debt / Capitalization	38.6%	37.1%	36.5%	37.2%	40.6%

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Source: Moody's Financial
Source: Moody's Investors Service

Detailed Rating Considerations

CONSTRUCTIVE ARIZONA REGULATORY FRAMEWORK SUPPORTS CREDIT QUALITY

Pinnacle derives essentially all of its operating cash flow from its regulated electric utility subsidiary, APS. We consider the Arizona utility regulatory framework to be constructive and supportive of the utility's long-term credit quality. Over the years, the ACC has made significant progress in improving its credit supportive framework for the state's investor-owned regulated utilities. Actions taken by the ACC have included: 1) shortening the time taken to finalize rate case orders to less than 12 months, on average; 2) providing a broad group of cost recovery mechanisms; and 3) pro-actively monitoring and addressing the cost-shift issue associated with distributed generation. These actions are credit supportive for APS and have enabled APS to earn close to its allowed return on equity (ROE) and maintain a strong financial profile including cash flow from operations pre-working capital (CFO pre-W/C) to debt of 24.5% for the twelve months ended March 31, 2107.

On March 1, 2017, APS announced that it had reached a settlement with key interested parties including the Arizona Corporation Commission (ACC) Staff, the Residential Utility Consumer Office and private rooftop solar organizations on the rate case it filed with the ACC on June 1, 2016. Although the settlement still requires approval by the ACC, we viewed the settlement as a significant step closer to getting the rate case concluded in a timely manner, which would help reduce regulatory lag, a credit positive. Timely rulings are especially important for utilities operating in Arizona, due to the ACC's use of a historical test year which utilizes an end of test year rate base to set future rates. We expect the regulators' approval by midyear with new rates effective at or around July 1, 2017.

The settlement includes an $87 million non-fuel, non-depreciation base revenue increase and the potential for an additional non-fuel base revenue increase related to costs associated with APS' proposed addition of selective catalytic reduction equipment at its coal-fired Four Corners Power Plant. The agreement as announced is slightly more than half of APS' request of $165.9 million and includes a return on equity of 10% and a 55.8% equity ratio. APS also will not be allowed to file a new general rate case application before June 1, 2019.

TIMELY COST RECOVERY MECHANISMS FURTHER ENHANCE CREDIT QUALITY

The ACC allows APS to use multiple cost recovery mechanisms to improve the collection of its rate base revenue. The settlement allows APS to continue to use key rate adjustment recovery mechanisms to maintain timely recovery of prudent costs and investments. Some of the mechanisms include partial decoupling through a Lost Fixed Cost Recovery (LFCR) rate mechanism, which allows for recovery of an estimated 30%-40% of lost revenues associated with energy efficiency and demand-side management. The LFCR mechanism essentially recovers revenues associated with fixed costs associated with distribution but not generation. We view decoupling mechanisms as credit supportive since they can reduce the uncertainty and volatility in cash flow. While the LFCR is credit positive, its impact is limited to recovery of lost revenues that result from energy efficiency and distributed generation investments as compared to full decoupling which provides for the recovery of weather-related losses as well.

APS will continue to recover fuel and purchased power costs through a power supply adjuster mechanism. The mechanism incorporates forward and true-up components that are intended to allow the utilities to recover fuel, purchased power and gas costs in a timely manner. APS will also allowed to continue to implement a surcharge to recover its renewable investments and above-market cost of power purchase agreements through the Renewable Energy Standard and Tariff. In addition, the utility is authorized to apply a surcharge to recover its investments in Demand Side Management to meet efficiency standards.

In addition, APS adjusts rates for US Federal Energy Regulatory Commission-approved transmission investments through a transmission cost adjustor mechanism. APS can also implement surcharges to recover government-mandated environmental expenditures. We view the variety of rate riders and trackers offered by the ACC as a means to reduce the utility's recovery lag. The settlement also includes rate design changes, including higher fixed charges for customers to better align customer rates with APS' fixed cost structure, which are further discussed below.

ACC'S PROACTIVE MONITORING OF THE ROOFTOP SOLAR COST-SHIFT ISSUE AND DECISION TO PHASE-OUT NET METERING IS CREDIT POSITIVE

On December 20, 2016, the ACC voted to reform the state's net metering policies. This was in response to a Value and Cost of Distributed Generation docket that was under consideration by the ACC for over a year. Over the long-term, we believe the ACC's decision to phase-out net metering and address the cost-shift burden on non-rooftop solar customers and will ensure a more timely recovery for the state's utilities for fixed costs not recovered under the LFCR.

The ACC order addressed several net metering changes, including placing rooftop solar customers in a separate rate class; grandfathering current rooftop solar customers under existing net metering rules and rate design for 20 years; eliminating the banking of excess energy exported back to the grid for non-grandfathered distributed generation customers; and compensating non-grandfathered customers for their exported energy based on the distributed generation export rate in effect at the time of interconnection. The ACC will determine the value of the export energy based on a resource comparison proxy which uses a rolling 5-year historical average price for utility-scale projects or an avoided cost method which is based on a 5-year projection. The method will be chosen based on individual utility rate cases and will be updated annually using an appropriate formula.

Under conditions of APS's rate case settlement, existing solar customers will be grandfathered in under existing net-metered tariffs, while new solar customers will be offered 12.9 cents/kWh for their excess energy during the first year. The 12.9 cents/kWh will apply for customers who interconnect over the next year and the rate will be in effect for ten years. Customers who interconnect with the utility after the first year will get smaller payments as the compensation rate will gradually decline.

In addition, under the current rate structure rooftop solar customers pay a small fixed monthly charge of about $8-$17. The proposed settlement will increase the number of customers on time-of-use rates and set a basic service charge for residential rate classes ranging from $13-$20 a month. The demand charge will be based on the highest demand average over a one hour period during the on-peak period each month. Additionally all customer rates will be based on time of use, which will give customers more control over their energy bills and electricity consumption. These changes will not have an effect on APS's authorized revenue requirement, however they will help mitigate the cost-shift associated with distributed generation from rooftop solar customers to non-rooftop solar customers.

These orders followed the ACC's initial decision, in November 2013, to impose a charge of 70 cents per kilowatt system per month on APS's residential rooftop solar customers that filed applications to install panels after December 31, 2013. The surcharge equated to about $5 per month on the typical 7-kilowatt system that homeowners in Arizona install. The implementation of the surcharge supported our view that regulators will be proactive in monitoring the cost-shift issue with regard to distributed generation. APS currently has about 60,000 rooftop solar customers or about 5% of its approximately 1.2 million residential and business customers.

SOLID FINANCIAL PROFILE EXPECTED TO REMAIN STABLE

Pinnacle has maintained a strong financial profile including a ratio of cash flow from operations pre-working capital (CFO pre-W/C) to debt of 22.9% and cash flow interest coverage average of 6.3x for the twelve months ended March 31, 2017. Pinnacle has been able to maintain strong financial metrics given APS' good customer and load growth relative to the rest of the country, prudent cost management, and the utilization of a broad group of timely cost recovery mechanisms as APS has been able to earn close to its allowed ROE of 10%.

Over the next two years, we expect Pinnacle's financial metrics to remain stable including CFO pre-W/C to debt in the mid-20% range and cash flow interest coverage of over 6.5x. We expect a modest uptick in financial metrics in the middle of 2017 and beyond when APS implements new rates after the conclusion of its general rate case.

APS ACCOUNTS FOR ESSENTIALLY ALL EARNINGS AND CASH FLOWS, BUT NEWLY FORMED TRANSMISSION JV COULD PROVIDE FUTURE GROWTH OPPORTUNITIES

APS accounts for essentially all of Pinnacle's revenues, earnings and assets. Pinnacle's other subsidiaries include Bright Canyon Energy Corporation (BCE) and El Dorado, an unregulated subsidiary that owns minority interests in several energy-related investments and Arizona community-based ventures. As of December 31, 2016, El Dorado had total assets of about $11 million and minimal revenues and no earnings. We do not expect El Dorado to have a material impact on Pinnacle's financial results or to require any material amounts of capital for at least the next three years.

BCE, formed in July 2014, focuses on new transmission growth opportunities in the industry. In 2014, BCE entered into a 50/50 joint venture, called TransCanyon, with Berkshire Hathaway Energy Company (A3 stable). TransCanyon is pursuing independent transmission opportunities within the eleven states that comprise the Western Electricity Coordinating Council.

With APS accounting for essentially all of Pinnacles earnings and cash flows, Pinnacle is a stable and predictable holding company within the construct of the Arizona regulatory environment. In addition, Pinnacle's only long-term debt is a $125 million term-loan due December 2017, which they plan to refinance later this year. As such, Pinnacle's A3 senior unsecured rating is one-notch lower than APS' A2 senior unsecured rating to reflect the structural subordination of the parent's obligations to creditors at the utility level. A departure from management's renewed focus on its regulated utility through new unregulated business investments or a significant increase in parent level debt would be credit negative.

Liquidity Analysis

As a holding company, Pinnacle's Prime-2 short term rating is based on its solid liquidity profile via upstream dividends from APS as well as its $200 million revolving credit facility which expires in May 2021. In 2016, APS distributed $281 million of dividends to Pinnacle representing a 61% payout of the utility's net income, which covered all of Pinnacle's $274 million dividends to shareholders (62% payout of income). Going forward, we expect APS' dividend payout will increase coinciding with earnings growth as Pinnacle's dividend payout is expected to be in the 60% - 70% range consistent with its historical average payout as management's stated dividend target growth rate is 5%.

Pinnacle's $200 million credit facility backstops its $200 million commercial paper program. Pinnacle has the option to increase the amount of the facility up to a maximum of $300 million with the consent of its lenders. As of March 31, 2017, Pinnacle had $43 million commercial paper borrowings outstanding no letters of credit issued and approximately $3 million of cash on hand. The credit facility's financial covenant requires a maximum debt to capital ratio of 65%. As of March 31, 2017, the ratio was approximately 49%.

The only debt Pinnacle has is a $125 million bank term-loan facility maturing December 2017. APS' next significant maturity is $500 million of notes due in March 2019.

Profile

Headquartered in Phoenix, AZ, Pinnacle West Capital Corporation (Pinnacle) is a holding company whose principal operating subsidiary, Arizona Public Service Company (APS: A2 stable), is a regulated vertically-integrated electric utility providing electric service to about 1.2 million homes and businesses in 11 of the 15 counties in Arizona. APS is regulated by the Arizona Corporation Commission and represents essentially all of Pinnacle's consolidated assets and revenues. Pinnacle's other main subsidiary is Bright Canyon Energy (BCE, unrated). BCE , formed in July 2014, entered into a 50/50 joint venture, called TransCanyon, with Berkshire Hathaway Energy Company (A3 stable). TransCanyon pursues independent transmission opportunities within the eleven states that comprise the Western Electricity Coordinating Council.

Rating Methodology and Scorecard Factors

Exhibit 3

Rating Factors				
Pinnacle West Capital Corporation				
Regulated Electric and Gas Utilities Industry Grid [1][2]	Current FY 12/31/2016		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.5x	Aa	6.1x - 6.6x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	26.7%	A	24% - 29%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	20.8%	A	18% - 23%	A
d) Debt / Capitalization (3 Year Avg)	37.4%	A	34% - 39%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching	-1	-1	-1	-1
a) Indicated Rating from Grid		A3		A3
b) Actual Rating Assigned		A3		A3

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2]As of 12/31/2016; Source: Moody's Financial Metrics™
[3]This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Investors Service

Ratings

Exhibit 4

Category	Moody's Rating
PINNACLE WEST CAPITAL CORPORATION	
Outlook	Stable
Issuer Rating	A3
Sr Unsec Bank Credit Facility	A3
Senior Unsecured Shelf	(P)A3
ARIZONA PUBLIC SERVICE COMPANY	
Outlook	Stable
Issuer Rating	A2
Sr Unsec Bank Credit Facility	A2
Senior Unsecured	A2

Source: Moody's Investors Service

REPORT NUMBER 1071734

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
23 June 2017

Update

Rate this Research

RATINGS

PNM Resources, Inc.

Domicile	Albuquerque, New Mexico, United States
Long Term Rating	Baa3
Type	LT Issuer Rating - Dom Curr
Outlook	Positive

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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CLIENT SERVICES

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Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

PNM Resources, Inc.

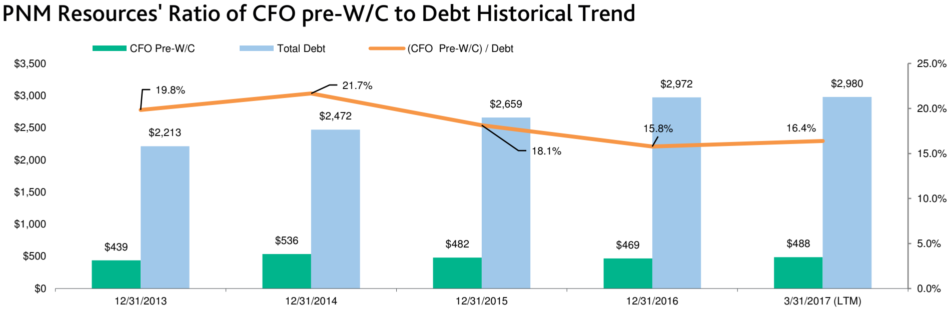
Regulated Utility Holding Company

Summary Rating Rationale

PNM Resources, Inc.'s (PNMR) Baa3 issuer rating is primarily driven by the credit quality of its principal utility subsidiary, Public Service Company of New Mexico (PNM, Baa2 positive), its solid financial profile including a ratio of cash flow from operations pre-working capital (CFO pre-W/C) to debt in the mid-to-high teens range and a view that capital expenditures will be financed in a balanced manner consistent with PNMR's current financial position. The rating also incorporates a New Mexico regulatory environment that has demonstrated signs of inconsistency and unpredictability with recent events resulting in increased regulatory lag for PNM. PNMR's rating also reflects the low risk nature of its T&D business at Texas-New Mexico Power Company (TNMP, A3 stable) and the credit supportive regulatory environment of the Electric Reliability Council of Texas (ERCOT) system in which it operates. The rating also reflects the expectation that management will continue to maintain its focus on regulated operations.

Exhibit 1

PNM Resources' Ratio of CFO pre-W/C to Debt Historical Trend



Source: Moody's Investors Service

Credit Strengths

» Low risk transmission and distribution business of TNMP operates in credit supportive regulatory jurisdiction of ERCOT with timely cost recovery mechanisms

» Use of future test-year in PNM's proposed rate case settlement currently under review by commission

» San Juan Generating Station (SJGS) environment compliance implementation plan provides certainty on majority of environmental investments

» Solid financial metrics expected to remain stable are strong for the rating

Credit Challenges

» Challenging regulatory environment in New Mexico that is less consistent and predictable compared to most other jurisdictions

» PNM has exhibited flat to declining load growth over several years

» Westmoreland loan adds to parent level debt and increased credit risk associated with low-rated counterparty

» Reduction in coal generation at PNM over the long-term could encounter push back from intervening parties and timely recovery depending on regulatory decisions

Rating Outlook

PNMR's positive rating outlook reflects our expectation that PNMR's financial metrics will remain strong for the current rating including a ratio of CFO pre-W/C to debt in the mid-to-high teens range. The strong financial metrics help offset a challenging New Mexico regulatory environment. The positive outlook also incorporates a view that the NMPRC will rule on PNM's rate case settlement by the end of this year such that the final outcome will not be materially different from what was proposed. Furthermore, the positive outlook also incorporates our expectation that planned capital expenditures will be financed in a balanced manner that is consistent with PNMR's current capital structure.

Factors that Could Lead to an Upgrade

PNMR's rating would likely move upward in the next 12-18 months if PNM's rating was to be upgraded; or if we observe a sustained improvement in the credit supportiveness of the New Mexico regulatory environment that includes greater predictability, timeliness and/or sufficiency of rates including a final order on PNM's rate case settlement by the NMPRC without material changes. In addition, PNMR and PNM's financial metrics are expected to remain strong such that PNMR's ratio of CFO pre-W/C to debt remains in the mid-to-high teens and PNM's ratio of CFO pre-W/C to debt were to remain around 20% on a sustained basis.

Factors that Could Lead to a Downgrade

PNMR's rating outlook could be changed to stable if the final outcome of PNM's rate case settlement is materially changed to the detriment of PNM's credit profile, or if we believe that PNMR will not be able to maintain strong financial metrics that are commensurate with a higher rating. The rating could be downgraded if we observe that the New Mexico regulatory framework has become less credit supportive or more unpredictable which results in unexpectedly adverse regulatory decisions or cost recovery disallowances; or if PNMR's financial metrics deteriorated such that its ratio of CFO pre-W/C to debt were to decline below 13% on a sustained basis.

Key Indicators

Exhibit 2

	3/31/2017(L)	12/31/2016	12/31/2015	12/31/2014	12/31/2013
CFO pre-WC + Interest / Interest	4.3x	4.2x	4.4x	4.9x	4.1x
CFO pre-WC / Debt	16.4%	15.8%	18.1%	21.7%	19.8%
CFO pre-WC – Dividends / Debt	14.0%	13.4%	15.7%	19.3%	17.5%
Debt / Capitalization	52.4%	52.5%	50.5%	48.1%	46.1%

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Source: Moody's Financial
Source: Moody's Investors Service

Detailed Rating Considerations

NEW MEXICO REGULATORY ENVIRONMENT HAS DEMONSTRATED SIGNS OF INCONSISTENCY AND UNPREDICTABILITY

Due to various regulatory decisions in New Mexico, we view the regulatory framework as being less predictable and transparent compared to other US jurisdictions. The most recent example occurred on 12 May 2017, when the hearing examiner presiding over PNM's current general rate case, which was filed in December 2016, issued an order rejecting a proposed settlement agreement. We view the rejection as credit negative due to the fact that 13 key parties involved had already agreed to the main terms of the settlement. Additionally we see the rejection as a continuation of a more contentious regulatory relationship in New Mexico compared to most jurisdictions in the US, which was also evident throughout PNM's 2015 rate case proceedings. PNM addressed the hearing examiner's concerns and submitted a revised settlement on 23 May 2017.

The revised settlement closely resembled the initial settlement agreement, including a $62.3 million phased-in (non-fuel) base revenue increase, with a $32.3 million increase on 1 January 2018 and a $30 million increase on 1 January 2019. The phased-in rate increase seeks to mitigate some of the immediate rate effect on customers. The agreement is more than half of PNM's original request of $99.2 million and includes a return on equity of 9.575% and a 50% equity ratio, which are both consistent with what regulators approved in PNM's 2015 rate case. Customer rates will also be frozen from general rate increases through 1 January 2020.

PNM will recover the costs of the pollution-control equipment installed at its coal-fired Four Corners Power Plant, but will forego the opportunity to earn a full return on that investment. Under the terms of the revised settlement, there will no longer be a second phase of the rate case to address rate design. Rather, PNM will need to file a separate docket to address rate design including PNM's proposed lost contribution of the fixed costs mechanism, which allows the recovery of a portion of lost revenues associated with energy efficiency and demand-side management. Any such mechanism could be put in place in PNM's next general rate case.

As was the case in the initial filed settlement, if approved without material changes, the revised settlement agreement would be viewed as a credit positive event for PNM. Rate case settlements usually result in a rate case decision more quickly than typically lengthy fully litigated rate cases. We expect the NMPRC's approval before the end of the year.

PNM's last rate case was implemented in September 2016 resulting in a 9.575% ROE and a $61 million rate increase. In the process of reaching a final decision the NMPRC ordered three extensions to the procedural schedule after rejecting PNM's initial application in December 2014. The 2014 rate case application was rejected on the recommendation of an independent hearing examiner. As part of the 2014 rejection, the regulators redefined the definition of a future test year as beginning up to 45 days following a rate case application. However, in November 2015, the NMPRC unanimously voted to once again re-define a future test year as the period beginning up to 13 months following a rate case application. Under the new and more traditional future test year definition, PNM is able to propose a test year a full year in advance of the date of its rate case filing, a credit positive. Due to inconsistent rulings throughout the rate case process, the time between the initial filing in 2014 and the final ruling in September 2016 was almost 21 months, much longer than the typical state rate case proceeding of about 12 months.

Under the terms of the final ruling the NMPRC also disallowed recovery of certain investments that PNM is in the process of appealing with the New Mexico Supreme Court. The three conditions disallowed by the commission include recovery of the full purchase price for 64 megawatts of previously leased capacity at Palo Verde, the unrecovered value of past leasehold improvements in the capacity, and the disallowance of the balanced draft technology installed at the SJGS. Final ruling by the Supreme Court on the appeal is not expected until late 2017 or early 2018.

LOW-RISK T&D BUSINESS OPERATES IN A CREDIT SUPPORTIVE REGULATORY JURISDICTION ERCOT WITH TIMELY COST RECOVERY MECHANISMS

TNMP's lower risk transmission and distribution operations are regulated by the Public Utility Commission of Texas (PUCT), a credit positive given the transparent and credit supportive regulatory framework that enables timely recovery of prudently incurred costs and investments. In addition, TNMP's T&D operations in ERCOT have no provider of last resort obligations which is a significant credit positive as TNMP is only obligated to deliver power that retail customers have requested from retail energy providers. Furthermore, TNMP utilizes formula based rate making for transmission investments and has the ability to utilize formula based ratemaking for distribution investments (although to date, they have yet to exercise this option). We believe that ERCOT's regulatory framework for

T&D's is generally more credit supportive than many state jurisdictions and is almost as supportive as federal transmission regulation. TNMP's last rate case settlement in 2011 resulted in a $10.25 million rate increase based on a 45% equity ratio and 10.125% authorized ROE. Although TNMP utilizes a historic test year in its rate cases, TNMP's formula-based rate making for transmission investments mitigates some of the recovery lag. TNMP is committed to filing a general rate case by 31 August 2018 with new rates expected to be effective in the first quarter of 2019.

As previously mentioned, TNMP utilizes formula based rate making for transmission investments through a transmission cost (TCOS) recovery rider and has the ability to utilize formula based ratemaking for distribution investments through a distribution cost (DCOS) recovery rider (although to date, they have yet to implement the DCOS rider). TNMP's ability to use both recovery mechanisms is credit positive. TNMP is allowed to update its transmission rates twice a year to recover investments including the addition and retirement of transmission facilities, including depreciation and taxes as well as an approved rate of return. On 23 March 2017, the PUCT staff filed proposed amendments to the interim TCOS filing rule, which if approved, could reduce the frequency of such filings to once per year. This would be credit negative as it could reduce timely recovery of some investments that TNMP was previously able to utilize. The PUCT is reviewing the amendments and has not yet approved the changes. Earlier this year, the PUCT approved TNMP's latest transmission application on 14 March 2017, which included an increase in total rate base of $30.2 million and an increase in revenues of $4.8 million.

In July 2011, the PUCT approved a settlement, which allowed TNMP to collect a surcharge of $113.4 million over a 12 year period for the deployment of an advanced meter system (AMS), also known as smart meters. The surcharge, which began collection in August 2011, has a true-up mechanism, which allows TNMP to match revenues collected against the expenses incurred and allows for a return to be earned on its investments. Deployment of smart meters began in September 2011 and was completed in 2016 with more than 242,000 installations. On 2 October 2015, TNMP filed a reconciliation of the costs and savings of its AMS deployment program that included $71 million in capital costs and $18 million in operation and maintenance expenses. TNMP did not request a change in the monthly customer surcharge. The PUCT approved the reconciliation without any adjustments on 25 March 2016. TNMP will include a final reconciliation of AMS costs in the 2018 rate case filing.

In 2014, the PUCT approved a stipulated agreement that will enable TNMP customers to opt-out of having an advanced meter used on their premises. The settlement assumed 1,081 ratepayers will elect the non-standard meter service, but can later be adjusted if the actual number differs. As of 24 April 2017, 103 customers have elected non-standard metering.

In addition, the PUCT allows TNMP to recover the costs of its energy efficiency programs through an energy efficiency cost recovery factor. TNMP's energy efficiency cost recovery factor of $6 million went into effect beginning 1 March 2017 with an incentive bonus of $0.8 million for achieving demand savings that exceeded the goal.

INVESTMENTS TO FURTHER DIVERSIFY PNM'S GENERATION PORTFOLIO INCLUDING THE EXIT OF COAL OVER THE LONG TERM COULD BE IMPACTED BY REGULATORY RECOVERY

On 21 April 2017, PNM filed its latest draft integrated resource plan (IRP) in which the company outlined its plan to be free of coal-fired generation by 2031. The draft IRP states that PNM will retire SJGS Units 1 and 4 after June 2022 when the coal supply and San Juan ownership restructuring agreements expire. In addition, PNM plans to exit its 13% stake in the Four Corners power plant in 2031 after that coal supply agreement also expires. The most cost effective portfolio according to the IRP recommends retaining the 114 MW of leased interests in the Palo Verde nuclear plant and replacing SJGS with 450 MW of gas peaking generation and 150MW of solar power. Although the current plan could increase customer rates in the short term, over the long-term management believes the plan could provide significant benefits to both customers and the environment. From a credit perspective it will be important for PNM to continue to receive timely recovery of environmental compliance investments in these plants. Cost recovery associated with the selective non-catalytic reduction (SNCR) technology on SJGS Units 1 and 4 will be accelerated so that all costs are fully recovered by July 1, 2022. However, cost recovery of the balanced draft technology was disallowed in PNM's 2015 rate case and is currently under appeal with the New Mexico Supreme Court.

On 16 December 2015, the NMPRC approved a final settlement agreement agreed upon by PNM and most interested parties to ensure that SJGS complies with the EPA regional haze rule. Under the settlement agreement PNM will retire Units 2 and 3 of SJGS on 31 December 2017 and will be allowed to recover 50% of the undepreciated net book value and earn a regulated return on those costs. As of 31 March 2017, PNM estimates the undepreciated net book value is approximately $265.4 million of which, 50% will be recovered over a 20 year period. As of 31 March 2017, PNM had recorded a $128.6 million regulatory disallowance to reflect the write-off of 50% of the uncollected book value. As part of the agreement, PNM was required to acquire an additional 65 MW of SJGS Unit 4 as a merchant utility plant that could not be billed in retail customer rates. As a result, PNM's ownership interest in SJGS Unit 4 increased to approximately 77% from approximately 64%.

The agreement approved by the NMPRC ended several years of negotiating amongst PNM and other interest parties including the New Mexico Environment Department (NMED), the United States Environmental Protection Agency (EPA), the NMPRC and its staff and numerous intervenors. PNM had filed an earlier settlement agreement with the NMPRC in October 2014. However, the earlier settlement agreement was rejected by the NMPRC based on the recommendation of an independent hearing examiner in April 2015. The lengthy delay and disagreements exhibited by the NMPRC and other parties during the SJGS environmental compliance proceedings was yet another example of the inconsistency and unpredictability as well as inadequate communication amongst key parties within the New Mexico regulatory environment.

FINANCIAL METRICS EXPECTED TO REMAIN STABLE AND COMMENSERATE WITH A HIGHER RATING

Although the New Mexico regulatory environment remains challenging, PNMR has been able to maintain strong financial metrics that are similar to Baa2 rated peers. Going forward, we expect PNMR's financial metrics to remain stable particularly as new rates are expected to go into effect PNM in January 2018 and then again in January 2019 as proposed in PNM's current rate settlement. Over the next two years, we expect PNMR's ratio of CFO pre-W/C to debt to be in the mid-to-high teens range and retained cash flow (RCF or CFO pre-W/C less dividends) to debt in the low-teens range.

For the twelve months ended 31 March 2017, PNMR's three-year average ratio of CFO pre-W/C to debt and RCF to debt were 17.6% and 15.2%, respectively, which are both consistent with Baa2 rated regulated electric utility holding company peers.

Over the past few years PNM has not been able to earn its authorized ROE, partly attributed to regulatory lag. After adjusting for goodwill and other unusual items, PNM's earned GAAP ROE in 2016 was approximately 5.7%, which is lower than the three year average of about 7.2%. The lower earned ROE in 2016 could be attributed to the 21 month lag between the time PNM filled its last rate case in 2014 and the final order in September 2016. In addition to new rates taking affect, we believe the use of a future test year in PNM's current rate case filing will better allow PNM to earn a return close to its authorized ROE.

WESTMORELAND LOAN ADDS TO PARENT LEVEL DEBT AND INCREASED CREDIT RISK ASSOCIATED WITH LOW CREDITWORTHY COUNTERPARTY

PNMR's parent debt level increased to approximately 14% of consolidated long-term debt as of 31 March 2017. PNMR's long-term debt includes a $150 million term loan due on or before 9 March 2018 and a $125 million term loan due 1 February 2021. An increase in holding company leverage from these levels, although not expected, would be credit negative. If parent level debt becomes substantial it could have negative implications across the whole family including a potential wider notching between the parent and its utilities' ratings.

The increase in parent level debt is primarily due to a $125 million term loan agreement entered into with The Bank of Tokyo-Mitsubishi UFJ, Ltd. by a newly created PNMR wholly-owned subsidiary, NM Capital Utility Corporation (NM Capital, unrated), on 1 February 2016. The term loan has a maturity date 1 February 2021 and is guaranteed by PNMR. The term loan includes customary covenants, including a maximum debt-to-capital ratio of 65% at PNMR.

The proceeds from the term-loan were used to fund a $125 million term loan agreement NM Capital entered into with a ring-fenced, bankruptcy remote subsidiary of Westmoreland Coal Company (Westmoreland, Caa1 stable) to help Westmoreland finance its purchase of the San Juan coal mine in February 2016. PNMR's $125 million term loan agreement with Westmoreland is credit negative because there is repayment risk on a loan to a speculative-grade rated coal mining company and it adds complexity to PNMR's financial profile.

PNMR's loan agreement with the Westmoreland subsidiary also has a maturity date of 1 February 2021 and was structured to encourage early prepayment by including an aggressive amortization schedule and an escalating coupon rate. As of 31 March 2017, the amount outstanding under the loan was $85.4 million. Westmoreland's acquisition of the San Juan coal mine was an important component in the final SJGS settlement agreement that was approved by the NMPRC in December 2015.

Liquidity Analysis

PNMR's sufficient liquidity profile is supported by dividend distributions from PNM and TNMP as well as availability on PNMR's revolving credit facilities. In 2016, PNMR's regulated subsidiaries paid dividends of only $37 million which is considerably lower than the approximately $128 million upstreamed to the parent in 2015. Dividends received from its subsidiaries can vary year to year depending on the parent's capital contributions, short-term borrowing needs and planned capital expenditures. PNMR paid common shareholder dividend distributions of $71 million in 2016, which was an income payout ratio of 57%. We expect PNMR will maintain a dividend payout ratio of 50-60% of on-going earnings, consistent with management's targeted range. In addition, we anticipate PNMR will continue to distribute capital contributions to its subsidiaries as needed to maintain their debt to capitalization ratios of around 50-55%. Going forward, we expect subsidiary dividends should generally cover the less than $15 million of parent debt interest expense plus common shareholder dividend distributions.

PNMR has a $300 million parent level revolving credit facility expiring in October 2021 with the exception of $10 million, which expires in October 2020. As of 24 April 2017, PNMR had $156.1 million of borrowing outstanding under its revolving credit facility along with $6.2 million of letters of credit and $2 million of cash on hand. The revolver's only financial maintenance covenant requires a maximum debt to capital ratio of 65%. As of 31 March 2017, PNMR's debt to capital ratio was approximately 62%. PNMR's long-term debt includes a $150 million term loan due on or before 9 March 2018, a $100 million term loan due on or before 21 December 2018, and a $125 million term loan due 1 February 2021 that had a principal balance outstanding of $82.8 million on 31 March 2017.

PNMR's subsidiaries can also borrow from the parent under one year loan arrangement up to $100 million for PNM and $50 million for TNMP. As of 24 April 2017, TNMP had $5 million of borrowings from PNMR.

Profile

PNM Resources, Inc. is a regulated electric utility holding company headquartered in Albuquerque, NM, whose principal subsidiary is Public Service Company of New Mexico (Baa2 positive), a vertically integrated electric utility in New Mexico regulated by the New Mexico Public Regulation Commission. PNMR's other subsidiary is the smaller Texas-New Mexico Power Company (A3 stable), which is an electric transmission and distribution utility regulated by the Public Utility Commission of Texas in the Electric Reliability Council of Texas system. Combined, PNM serves over 760,000 customers in New Mexico and Texas with over 24,000 miles of T&D lines and almost 2,800 MW generating capacity. PNM accounts for about 80% of PNMR's total revenues and about 70% of earnings, while TNMP essentially accounts for the remainder.

Rating Methodology and Scorecard Factors

Exhibit 3

Rating Factors				
PNM Resources, Inc.				
Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 3/31/2017		Moody's 12-18 Month Forward View As of Date Published[3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Baa	Baa	Baa	Baa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	Ba	Ba	Ba	Ba
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.5x	Baa	4.3x - 4.8x	A
b) CFO pre-WC / Debt (3 Year Avg)	17.6%	Baa	15% - 20%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	15.2%	Baa	12% - 18%	Baa
d) Debt / Capitalization (3 Year Avg)	51.3%	Baa	47% - 52%	Baa
Rating:				
Grid-Indicated Rating Before Notching Adjustment		Baa2		Baa2
HoldCo Structural Subordination Notching	-1	-1	-1	-1
a) Indicated Rating from Grid		Baa3		Baa3
b) Actual Rating Assigned		Baa3		Baa3

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2]As of 3/31/2017(L); Source: Moody's Financial Metrics™
[3]This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Investors Service

Ratings

Exhibit 4

Category	Moody's Rating
PNM RESOURCES, INC.	
Outlook	Positive
Issuer Rating	Baa3
PUBLIC SERVICE COMPANY OF NEW MEXICO	
Outlook	Positive
Issuer Rating	Baa2
Senior Unsecured	Baa2
TEXAS-NEW MEXICO POWER COMPANY	
Outlook	Stable
Issuer Rating	A3
Sr Sec Bank Credit Facility	A1
First Mortgage Bonds	A1

Source: Moody's Investors Service

REPORT NUMBER 1076344

MOODY'S
INVESTORS SERVICE

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
11 February 2018

Update

Rate this Research

RATINGS

Southern Company (The)

Domicile	Atlanta, Georgia, United States
Long Term Rating	Baa2
Type	Senior Unsecured - Dom Curr
Outlook	Negative

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Southern Company (The)

Update following negative outlook

Summary

The Southern Company's (Southern) credit profile reflects its position as the parent company of several electric utilities operating in mostly credit supportive regulatory jurisdictions; a stable, relatively low risk natural gas local distribution company (LDC) business with generally supportive regulation; and a growing, unregulated, but highly contracted wholesale power company. These credit positives are offset by elevated business risk at its largest electric utility subsidiary, Georgia Power Company (Georgia Power, A3 negative), as it continues with construction of the Vogtle new nuclear construction project following approval by Georgia regulators. In addition, Southern has a relatively high level of holding company debt to consolidated debt at over 25%. Southern's cash flow coverage metrics will also be negatively affected by recent changes in tax law, absent mitigating regulatory actions or changes in Southern's financing plans.

On 21 December 2017, in a unanimous decision, the Georgia Public Service Commission (GPSC) approved Georgia Power's August 2017 recommendation that it complete the Vogtle project following the bankruptcy of the project's EPC contractor Westinghouse Electric Corporation LLC (unrated), the abandonment of the nearly identical Summer new nuclear project in South Carolina, and over the objection of the GPSC's Public Interest Advocacy Staff. Risks associated with the project have been mitigated to some degree by the receipt of $1.7 billion of completion guarantee obligations from Westinghouse parent Toshiba Corporation (Caa1 stable) in 2017 and the continued support of Georgia Power's three Vogtle project co-owners.

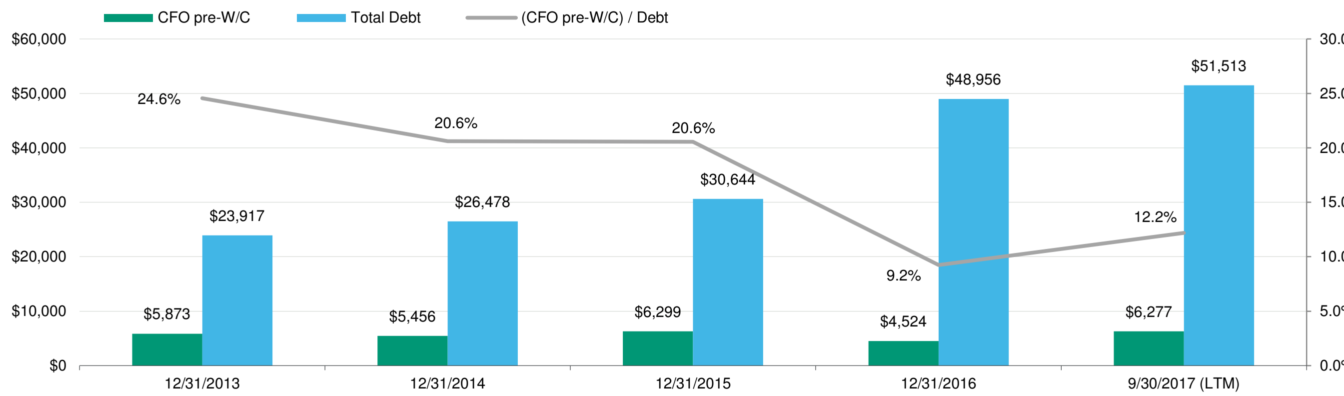
After an evaluation of the projected cost and schedule to complete Vogtle following the Westinghouse bankruptcy, Georgia Power now expects its share of the project's capital costs to be approximately $8.8 billion (about double the original capital cost of $4.4 billion), before netting the Toshiba guarantee payments and customer refunds. Total project costs for Georgia Power's share, including financing costs, are now estimated at $12.2 billion, compared to the original estimate of $6.1 billion. The utility's revised base case in-service dates are now November 2021 (Unit 3) and November 2022 (Unit 4), over five years after the originally projected completion dates of April 2016 and April 2017, respectively. Southern is moving forward without the protection of a fixed price construction contract with its affiliate, Southern Nuclear Operating Company, Inc. (Southern Nuclear, unrated), taking over project management responsibilities. Bechtel Power Corporation (Bechtel, unrated) is now serving as the primary construction contractor to complete the project.

Mississippi Power Company's (Mississippi Power, Ba1 stable) credit profile has stabilized as it has resolved the regulatory and financial uncertainty associated with cost recovery on the Kemper Integrated Gasification Combined Cycle (IGCC) plant. After the Mississippi Public Service Commission (MPSC) determined that the plant should operate as a natural gas plant only, the company and the Mississippi Public Utilities Staff initially failed to reach an agreement on cost recovery on the natural gas portion of the plant. A settlement agreement was ultimately reached in December 2017, which was approved by the MPSC on 6 February 2017. Mississippi Power's credit profile should begin to improve now that Kemper cost recovery issues have been resolved, the utility addresses the short-term financing it has relied upon in recent years, and financial coverage metrics improve.

In late 2017, Southern announced the $1.7 billion sale of two of the LDC subsidiaries it acquired in 2016 and is also considering selling a minority equity interest in some of Southern Power Company's (Southern Power, Baa1 stable) solar assets. These transactions have the potential to be credit positive for Southern depending on the use of proceeds. To the extent the proceeds are used to reduce existing debt at the holding company, we would view the transactions as credit positive. If the proceeds are used solely to offset Southern's future financing requirements, we would view them as more credit neutral, as they could help maintain but not necessarily improve Southern's credit profile.

Exhibit 1

Historical CFO pre-WC, Total Debt and CFO pre-WC to Debt [1]



[1] 2016 did not reflect a full-year of contributions from Southern Company Gas, as the acquisition closed on 1 July 2016.
Source: Moody's Financial Metrics

Credit strengths

» Unanimous Georgia regulatory commission support for the continuation of the Vogtle new nuclear project

» Size, scale, and diversification of the Southern organization following natural gas company acquisitions in 2016, a key factor supporting Southern's credit profile in light of large construction project challenges

» Electric and gas utility subsidiaries operate in mostly credit supportive regulatory environments, with Alabama Power, Georgia Power, Gulf Power and Southern Company Gas having particularly supportive regulatory frameworks

» Subsidiary Mississippi Power's credit profile has stabilized and should begin to improve as it has resolved the financial and regulatory uncertainty associated with cost recovery on the Kemper IGCC plant

» Sale of LDC subsidiaries and possible sale of solar assets could result in a cash inflow, which has the potential to improve credit quality if used to reduce debt

Credit challenges

- High business and operating risk as the Southern moves forward with the Vogtle new nuclear project without a fixed price contract and assumes more of a nuclear construction management role
- Recently passed tax reform legislation will negatively affect financials absent mitigation measures and pressure Southern's ability to maintain metrics supportive of rating, including CFO pre-working capital to debt of at least 15%; the 30 September 2017 LTM ratio of 12.2% could fall to the 10% range without mitigation
- High percentage of debt at the Southern parent company of around 25% of consolidated debt could increase as equity levels at the utilities are raised to offset the impact of tax reform
- Negative outlooks at its two largest subsidiaries, Georgia Power Company (A3) and Alabama Power Company (A1)
- Debt incurred to fund substantial capital expenditures at Southern Power has negatively but temporarily affected that subsidiary's cash flow coverage metrics

Rating outlook

The negative rating outlook on Southern primarily reflects the pressure that recent tax reform legislation will have on financial metrics, absent mitigation measure, which will adversely affect the ability of Southern to maintain CFO pre-working capital to debt at or above 15%. The negative rating outlook also considers the negative outlooks on Southern's two largest utility subsidiaries, Georgia Power and Alabama Power.

Factors that could lead to an upgrade

An upgrade of Southern's rating is unlikely while it faces financial and execution risk at the Vogtle new nuclear project and CFO pre-working capital to debt remains at 15% or below. Southern's rating outlook could be stabilized if there are credit supportive regulatory actions at the state level to mitigate the impact of tax reform, or there is a change in Southern's corporate finance policies such that parent level debt is reduced or cash flow coverage metrics improve materially, incuding CFO pre-working capital to debt in the high teens to 20%.

Factors that could lead to a downgrade

Southern's rating could be downgraded if either Alabama Power, Georgia Power, or Southern Gas are downgraded; if there is a material debt financed acquisition, further increasing parent company leverage; if there are additional delays or cost increases at the Vogtle nuclear project; if recent tax reform legislation or other developments cause consolidated coverage metrics to show a sustained decline, including CFO pre-working capital to debt below 15%.

Key indicators

Exhibit 2

KEY INDICATORS [1][2]
Southern Company (The)

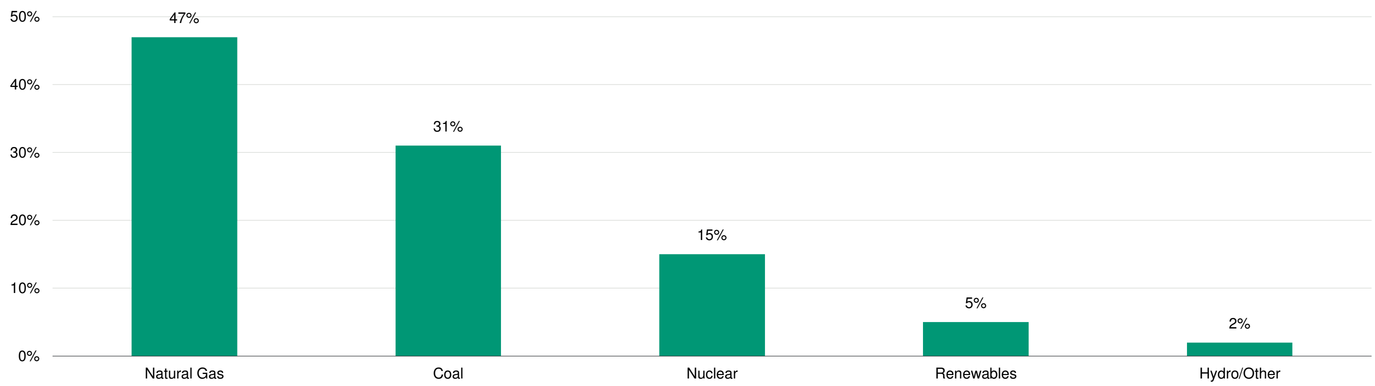
	12/31/2013	12/31/2014	12/31/2015	12/31/2016	9/30/2017(L)
CFO pre-WC + Interest / Interest	7.0x	6.6x	7.2x	4.0x	4.5x
CFO pre-WC / Debt	24.6%	20.6%	20.6%	9.2%	12.2%
CFO pre-WC – Dividends / Debt	16.9%	13.3%	15.2%	6.1%	8.2%
Debt / Capitalization	43.9%	45.0%	47.0%	54.2%	55.5%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] 2016 did not reflect a full-year of contributions from Southern Company Gas, as the acquisition closed on 1 July 2016.
Source: Moody's Financial Metrics

Profile

Based in Atlanta, GA, The Southern Company (Southern) is a utility holding company that owns four vertically integrated regulated utilities: Georgia Power Company, Alabama Power Company, Mississippi Power Company and Gulf Power Company. Southern also owns several local gas distribution companies under its Southern Company Gas subsidiary and is engaged in competitive electricity generation through Southern Power Company.

Exhibit 3
Southern has a diversified energy mix with nearly 50% natural gas in 2016



Source: Southern Investor Fact Sheet

Detailed credit considerations

- Unanimous Georgia regulatory commission support for continuation of the Vogtle new nuclear project

On 21 December 2017, the Georgia Public Service Commission (GPSC), by a 5-0 margin, accepted Georgia Power's August 2017 recommendation that it complete the Vogtle project following the bankruptcy of the project's EPC contractor Westinghouse Electric Corporation LLC (Westinghouse, unrated), the abandonment of the nearly identical VC Summer new nuclear project in South Carolina, and over the objections of the GPSC's Public Interest Advocacy Staff.

In its decision, the GPSC verified and approved $542 million of costs incurred under the 17th Vogtle Construction Monitoring Report (through 30 June 2017) and agreed that the revised $7.3 billion of Vogtle projected capital costs ($8.8 billion net of the $1.7 billion Toshiba guarantee payments and $188 million of customer refunds) and projected in-service dates (November 2021 and 2022) are reasonable. The GPSC also agreed that the revised capital cost forecast does not represent a cost cap and that prudence decisions on cost recovery will be made at a later date, which is consistent with a previous December 2016 regulatory settlement with the GPSC on Vogtle costs (outlined below). Under that settlement agreement, $5.68 billion of Vogtle capital costs incurred are presumed to be reasonable and prudent, with the burden of proof on any party challenging these costs.

Exhibit 4
Revised Vogtle Project Cost Estimates (Georgia Power Share)

Capital Costs through 9/30/17	Financing Costs through 9/30/17	New Projected Capital Costs	New Projected Financing Costs	Current Total Projected Cost
$4.6 billion	$1.5 billion	$8.8 billion (originally $4.4)	$3.4 billion (originally $1.7)	$12.2 billion (originally $6.1)

Source: Moody's Investors Service, Company Presentations

In addition, the US Department of Energy (DOE), which has provided loan guarantees to Georgia Power and two of the other co-owners has conditionally offered additional loan guarantees for the project, which would provide some modest additional cost savings.

Finally, Toshiba not only agreed to honor its $3.68 billion of completion guarantees for the project ($1.7 billion for Georgia Power), but paid it entirely in 2017, bolstering Georgia Power's liquidity and alleviating some of the project's cost pressure.

The GPSC decision included some penalties on Georgia Power's return on equity (ROE), with the ROE used to determine the utility's Nuclear Construction Cost Recovery Tariff falling to 8.3% from 10% on 1 January 2020 and again to 5.3% or the utility's average cost of long-term debt (whichever is higher) beginning 1 January 2021. The penalties are lifted once each individual unit is placed into service. There are some ROE incentives included to finish the project ahead of time in the form of an ROE reduction of 10 bps per month beginning 1 June 2021 (Unit 3) and 1 June 2022 (Unit 3). Finally, the GPSC required Georgia Power to refund approximately $188 million of the Toshiba guarantee funds received in the form of a $75 per customer credit. We expect these ROE penalties to have a minimal impact on Georgia Power's cash flow coverage metrics.

- High business and operating risk as Southern moves forward with the Vogtle project without a fixed price contract and assumes more of a nuclear plant construction management role

Georgia Power's recommendation to complete the project followed a detailed cost and schedule analysis undertaken by the company following the March 2017 bankruptcy of Westinghouse, due to the substantial cost increases at the Vogtle plant and the nearly identical Summer new nuclear plant project owned by South Carolina Electric & Gas Company's (SCE&G, Baa2 negative). SCE&G has subsequently abandoned construction of the Summer project and, as a result, Georgia Power will no longer have the benefit of shared knowledge from two identical nuclear plants being built ninety miles away.

Since the Westinghouse bankruptcy, Georgia Power and its co-owners have largely managed and successfully mitigated many of the issues that arose from losing its EPC contractor. For example, Georgia Power affiliate Southern Nuclear Operating Company, Inc. (Southern Nuclear, unrated) has taken over project management responsibilities and has engaged Bechtel Power Corporation (Bechtel, unrated) as construction contractor to complete the project. Bechtel was the lead construction contractor on the Tennessee Valley Authority's (Aaa stable) Watts Bar 2 nuclear plant, the only other nuclear plant recently constructed in the US, which came on line in 2016.

However, the transition of project management responsibility to Southern Nuclear has increased credit risk as Southern becomes more directly involved in the management and oversight of nuclear construction, which is well outside of their core competency of operating a regulated electric utility business. Southern's experience with subsidiary Mississippi Power Company's (Ba1 stable) Kemper generation project construction demonstrates the risks and pitfalls that can be encountered when a utility undertakes a major, first-of-a-kind generation project on its own.

- Tax reform legislation will negatively affect financial metrics absent mitigation measures, pressuring Southern's ability to maintain metrics supportive of rating, including CFO pre-working capital to debt of at least 15%

Recently passed US tax reform legislation is credit negative for Southern because the lower 21% statutory tax rate will create a cash flow shortfall at its regulated utilities, while the loss of bonus depreciation will reduce tax deferrals. We believe the tax law changes, absent mitigation, will dilute the ratio of CFO pre-working capital to debt by between 150 and 250 basis points on average for the industry, depending to some degree on the size of an individual utility's capital expenditure program. From a leverage perspective, we estimate that utility debt to capitalization ratios will increase, based on the lower value of deferred tax liabilities.

For these reasons, the rating outlooks of Southern and utility subsidiary Alabama Power were changed to negative from stable as both have limited flexibility in their current rating to accommodate a deterioration in their financial metrics. The tax reform legislation will also pressure the financial metrics of Southern's other utility subsidiaries, including Georgia Power, which already had a negative rating outlook. Absent mitigation measures on the part of regulators at Southern's utility subsidiaries or changes to Southern's corporate financing plans, Southern's ratio of CFO pre-working capital to debt is unlikely to be maintained at 15%, our previously indicated financial metric trigger for a potential downgrade. Southern's LTM 12.2% CFO pre-working capital to debt ratio could fall to the 10% range without mitigation.

- High percentage of debt at the Southern parent company of around 25% of consolidated debt could increase as regulated utility equity levels are raised to offset the impact of tax reform

Southern's credit profile was negatively affected by the primarily debt financed acquisition of AGL Resources Inc. (now called Southern Company Gas, unrated) last year. The $8 billion (debt portion) acquisition resulted in a significant increase in Southern holding company debt at a time when its holding company debt had already been increasing, partly to support funding needs at utility subsidiary Mississippi Power and for portfolio growth at Southern Power. The addition of nearly $8 billion of debt at the Southern holding company increased parent company debt from approximately $4 billion prior to the acquisition (12-13% of total consolidated debt) to approximately $12 billion (around 25% of consolidated debt at 31 December 2016), reducing cash flow coverage metrics. Parent company debt has been above 25% throughout 2017, pressuring cash flow coverage metrics.

For Southern, the issuance of significant additional debt at the parent company eliminated a key credit advantage that had distinguished the company from many of its peers; namely, the limited use of holding company leverage and the higher relative financial flexibility at the parent company. With this additional debt at the holding company level, structural subordination has increased and financial flexibility has been reduced. If equity levels are increased at the regulated utilities to offset the impact of tax reform, the percentage of parent company debt to total consolidated debt could increase and approach 30% or higher. For the LTM period ending 30 September 2017, Southern's CFO pre-working capital was $6.3 billion and approximately $13.4 billion of the company's $51.5 billion of total debt was at the parent company, or approximately 26%.

On 6 September 2016, Southern also invested approximately $1.47 billion to acquire a 50% equity interest in Southern Natural Gas Company (Baa2 stable), a major interstate natural gas pipeline, in a joint venture with Kinder Morgan Inc. (Baa3 stable). Unlike the AGL acquisition, Southern financed a significant portion of this transaction with equity, with little to no impact on its financial metrics. Although our published financial ratios and metrics do not include the pipeline's debt, we also analyze Southern with the proportional consolidation of the pipeline's debt. Southern intends to use the joint venture to pursue additional natural gas infrastructure projects and opportunities, a potential risk depending on the business risk profile, financing method, and amount of debt utilized.

- Electric and gas utility subsidiaries in mostly credit supportive regulatory jurisdictions, especially Alabama Power, Georgia Power, Gulf Power, and Southern Gas

Southern's rating is supported by the credit supportive regulatory environments in most of the jurisdictions in which it operates with generally constructive relationships with regulators and strong cost recovery provisions. The AGL acquisition has added some additional, mostly credit supportive, regulatory environments and increased the company's regulatory and geographic diversity, which will be only marginally diminished with the pending LDC subsidiary sales.

In Georgia, in addition to the unanimous regulatory support for the Vogtle project discussed above, Georgia Power has been operating under an Alternate Rate Plan for several years (the "2013 Alternate Rate Plan") that we view as credit supportive, particularly considering the additional annual rate increases associated with Vogtle. Under a settlement reached with the GPSC on 14 April 2016, the 2013 Alternate Rate Plan will continue in effect until 31 December 2019, and the company will be required to file its first rate case by 1 July 2019. Under the rate plan, the company increased its rates by approximately $136 million in 2015 and $140 million in 2016. Under this plan, the allowed earned ROE range is 10%-12%, down slightly from 10.25%-12.25%, with a sharing mechanism for earnings above this range. In 2016, the company's retail ROE exceeded 12% and the company refunded approximately $40 million to retail customers. If Georgia Power's ROE is projected to fall below 10%, the company can request an Interim Cost Recovery Tariff.

In Alabama, Southern's second largest jurisdiction, the regulatory environment has been credit supportive for Alabama Power. Rates are set under a Rate RSE (Rate Stabilization and Equalization) mechanism that establishes rates based on an allowed weighted cost of equity range (WCE) of 5.75% to 6.21%, with an adjusting point of 5.98%. The company can earn an additional 7 basis points if it maintains an A credit rating from one rating agency or is in the top third of a customer value (or service quality) benchmark that the Alabama Public Service Commission utilizes. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%.

In Florida, Gulf Power Company (A2 stable) benefits from several timely cost recovery provisions, including a Florida Public Service Commission (FPSC) approved fuel cost recovery mechanism that includes a true-up of actual fuel costs, a projection of future costs, and interest on the over/under recovery balance. The mechanism also allows for interim rate adjustments if the end of period over or under recovery exceeds 10% of the projected annual fuel revenues for the period.

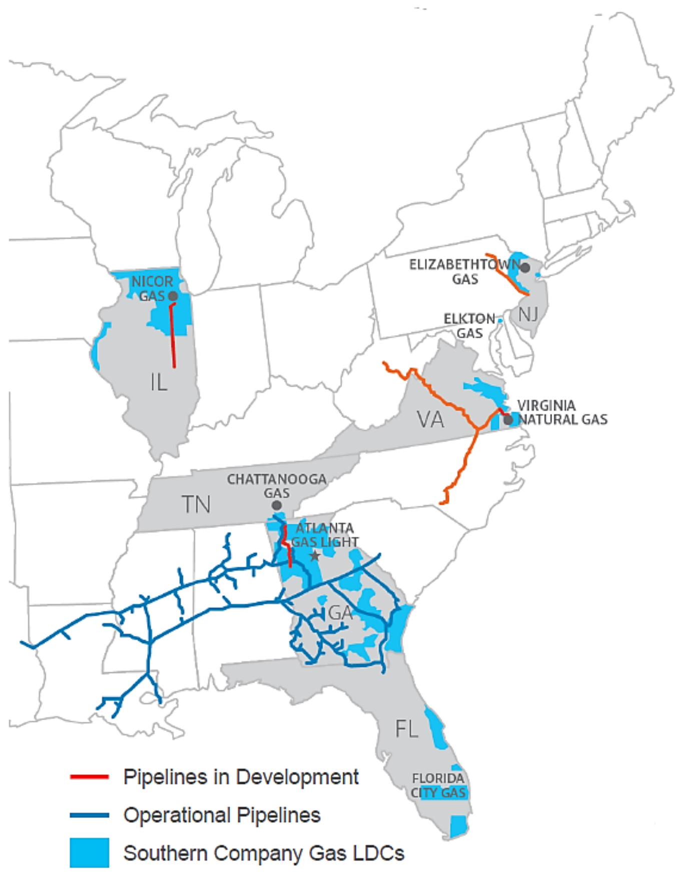
On 4 April 2017, the FPSC approved a credit supportive rate case settlement between Gulf Power and several intervenors. As part of the settlement, Gulf Power increased rates by $62 million on 1 July 2017, less an annual credit for certain wholesale revenues to be provided through December 2019, estimated to be $7.7 million for 2017. As a result, the net customer impact of the rate increase is $54.3 million. The settlement allowed Gulf Power to continue its currently authorized retail ROE midpoint of 10.25% and range of 9.25% to 11.25%; on a much higher equity ratio of 52.5%, up from 46% previously, above the national average.

Southern Gas has LDC operations in seven states with several rate cases pending, most notably a $208 million general rate case at Northern Illinois Gas Company (A2 stable). We consider the regulatory environments in Illinois, Georgia, New Jersey and Virginia, which make up the majority of total LDC operations, to be above average. Southern Gas has limited exposure to commodity price, weather and volume volatility due to margin-stabilizing rate mechanisms such as decoupling in Georgia, Tennessee, and Virginia; straight-fixed-variable rates in Georgia; and weather normalization in New Jersey, Tennessee, and Virginia. While the LDCs may experience some notable, but temporary, fluctuations in cash flow and debt metrics during a period of changing gas prices and volume demands, these costs are recovered on a timely manner under purchased gas recovery mechanisms.

- Sale of LDC subsidiaries and possible sale of solar assets could result in a cash inflow, which has the potential to improve credit quality if used to reduce debt

On 16 October 2017, Southern announced that Pivotal Utility Holdings, Inc. (unrated), a wholly-owned subsidiary of Southern Gas, had entered into an agreement to sell two of its smaller natural gas LDC subsidiaries, Elizabeth Town Gas, Inc. (Elizabethtown Gas, unrated) and Elkton Gas Co. (Elkton Gas, unrated), to South Jersey Industries, Inc. (SJI, unrated). The total transaction value is estimated at approximately $1.7 billion, which incorporates an effective purchase price of $1.4 billion and approximately $300 million associated with the present value of tax benefits related to the transaction. The transaction is expected to close in mid-2018 and is subject to several state and federal approvals including the Hart-Scott Rodino Act, the New Jersey Board of Public Utilities, the Maryland Public Service Commission, and the Federal Energy Regulatory Commission.

Exhibit 5
Southern Company Gas Operations



Source: Southern Presentation (2017 American Gas Association Financial Forum)

Southern is also considering launching a process to sell a minority interest in Southern Power's portfolio of solar assets, with a potential closing in mid-2018. These transactions have the potential to be credit positive for Southern depending on the use of proceeds. To the extent the proceeds are used to reduce existing debt at the parent company, we would view the transaction as credit positive. If the proceeds are used solely to offset Southern Company's future debt financing requirements, we would view the transaction as more credit neutral, maintaining but not necessarily improving Southern's credit profile. Southern has yet to announce details for the use of the proceeds including any elimination of specific debt and/or equity needs.

- Mississippi Power's credit profile has stabilized as it has resolved cost recovery issues associated with the Kemper IGCC plant, although the regulatory environment and financial condition have been negatively affected

Subsidiary Mississippi Power's credit reflects the decline in the utility's regulatory environment caused by several years of delays and cost overruns on the Kemper IGCC plant, construction of which was suspended in June 2017. This suspension followed a MPSC order indicating that the plant should operate as a natural gas facility only without the gasifier and related assets, the far more expensive part of the facility. At the time of the suspension, the cost estimate for the plant had reached $7.38 billion, up from $2.4 billion originally. As a result of the MPSC order, and because cost recovery on the gasifier portion of the plant was no longer likely, Mississippi Power recorded an additional charge to income of $2.8 billion ($2 billion after tax) as of 30 June 2017, bringing total Kemper charges to $6.0 billion ($3.9 billion after tax).

On 1 December 2017, Mississippi Power, the Mississippi Public Utilities Staff, and other intervenors reached a settlement providing for an annual revenue requirement of $112.6 million for costs related to the Kemper plant based on a fixed ROE of 8.6% for 2018 and 2019, a performance based ROE for future years, and amortization periods for regulatory assets and liabilities for eight and six years, respectively.

On 6 February 2018, the MPSC approved the settlement, lowering the annual revenue requirement to approximately $99.3 million for costs related to the Kemper facility solely to account for the impact of federal tax reform legislation passed in December. The revenue requirement also reflects a disallowance related to a portion of Mississippi Power's investment in Kemper requested for inclusion in rate base, which Southern and Mississippi Power recorded in the fourth quarter of 2017 as an additional charge to income of approximately $78 million ($85 million net of accumulated depreciation of $7 million) pre-tax ($48 million after tax). Under the settlement, retail customer rates will reflect a reduction of approximately $26.8 million annually, with no recovery for costs associated with the gasifier portion of the Kemper facility.

While Mississippi Power's financial condition has declined over the course of the Kemper construction period, the utility has been supported by substantial capital contributions and liquidity support from Southern. This included a $1 billion equity contribution in June 2017, following the suspension order, that improved the utility's liquidity profile and reduced debt levels. Although the utility's regulatory environment is likely to remain challenged, the utility's financial metrics should now begin to improve relatively quickly for the most part due to the deferred tax benefits that the utility will receive. The utility will also return to a more normalized level of capital expenditures post-Kemper. The magnitude of the increase in coverage metrics will be somewhat dependent on continued regulatory support for cost recovery under Mississippi Power's performance evaluation plan (PEP) going forward.

- Southern Power is mostly contracted, although higher debt to fund rapid growth has increased leverage and resulted in temporarily poor cash flow coverage metrics

Southern Power, Southern's wholesale power subsidiary, has a lower business risk profile relative to other competitive wholesale generators based on the company's strategy of entering into long-term contracts with creditworthy counterparties for most of its generation output. However, Southern Power has a comparatively higher level of business risk than Southern's core retail regulated utility subsidiaries due to the lack of regulated cost recovery provisions and because it's primary operations are in the competitive wholesale power markets.

Southern Power's cash flow coverage metrics have been volatile in recent years, exhibiting particularly strong coverage metrics in 2012 and 2013, with CFO pre-W/C to debt in the 40% range due to the receipt of substantial investment tax credits on new solar projects and the positive impact of bonus depreciation. CFO pre-W/C to debt fell to 15.6% in 2014 due to the carry forward of $305 million of investment tax credits into 2015, before recovering to 23% in 2015.

In 2016, the company's CFO pre-W/C to debt was negative 9.9%, before increasing to 6.9% for the twelve months ended 30 September 2017, as nearly $4 billion of long-term debt was issued to finance capital expenditures for renewable project developments. While Southern Power also received capital contributions from the Southern parent company of approximately $2.5 billion over this period to help fund this growth, the combination of higher debt, limited cash flow from new projects, and substantially higher deferred income tax credits all contributed to unusually low coverage metrics in 2016 and 2017. We expect these metrics to improve closer to prior year levels in the 20% range, our expected run rate going forward, as capital expenditures decline to more normalized levels and new projects begin to generate cash flow. Pending solar asset sales may also be used to reduce debt.

In 2016, Southern Power's growth capital expenditures for renewable energy development increased to $4.4 billion from $2.4 billion the prior year, and the company has said that it expected 2016 to be a "high-water" mark for the company's expansion into renewables. The company indicated that it saw a larger pipeline of renewable projects than originally anticipated and completed several incremental wind projects after its earlier focus was for the most part on solar. The company currently expects capital expenditures to be much lower at $1.5 billion annually for the next few years and capital expenditures totaled $1.3 billion for the first nine months of 2017.

Liquidity analysis

Southern exhibits an adequate liquidity profile, although the Southern organization has a sizable $3.5 billion of long-term debt and $2.6 billion of notes payable coming due over the 12 month period ending 30 September 2018. Short-term debt (commercial paper and bank debt) was consistently elevated in 2017, with $2.6 billion outstanding at 30 September 2017, compared to $2.0 billion at 31 December 2016; and $1.2 million at 30 December 2015 (before the AGL acquisition). Liquidity is supported by the underlying cash flows of regulated electric and gas utility operating subsidiaries and its wholesale generation business; mostly unused bank credit facilities totaling $8.1 billion at the parent company and subsidiary levels; and a cash position of $1.8 billion as of 30 September 2017.

Only subsidiary Mississippi Power's standalone liquidity is relatively weak because of the high costs and lack of rate relief on the Kemper plant and the utility has been highly reliant on Southern, which provided the utility a $1 billion capital contribution in June 2017. The capital was used to repay $300 million of Mississippi Power's $1.2 billion bank loan, which the utility has relied upon in lieu of long-term bonds while the Kemper project was pending, and for the repayment of $591 million of promissory notes to the parent company.

Southern maintains $2 billion of credit facilities at the parent company with an expiration date in 2022. These credit facilities provide liquidity support for its commercial paper program and can be used for other short-term financing needs. The credit facility includes a covenant which limits Southern's debt to capital (excluding trust preferred securities, securitizations, and hybrid securities) to 70% and there are no material adverse change representations for new borrowings. As of 30 September 2017, Southern was in compliance with this financial covenant.

Unlike most other large utility companies that maintain a large, centralized bank credit facility and a money pool arrangement with their subsidiaries, each of Southern's utilities and Southern Power maintain their own bank facilities to support their short-term liquidity needs. Consolidated unused credit facilities were approximately $8.1 billion as of 30 September 2017, with $1.5 billion providing liquidity support to the utilities' variable rate pollution control revenue bonds. In addition, as of 30 September 2017, approximately $699 million of fixed rate pollution control bonds are required to be remarketed. Of these credit facilities, $130 million expires in 2017, $260 million in 2018, and $25 million in 2019, with the remaining expiring in subsequent years.

Exhibit 6

Southern exhibits an adequate liquidity profile, with largely unused credit facilities

As of 30 September 2017

	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	SEGCO	Southern Company Gas	Southern Power	Parent	Consolidated
Total Capacity	$1,335	$1,750	$280	$100	$30	$1,900	$750	$2,000	$8,145
Unused Credit Lines	$1,335	$1,732	$280	$100	$30	$1,861	$728	$2,000	$8,066
Cash [1]	$953	$266	$37	$231	$0	$21	$178	$25	$1,841
Total	**$2,288**	**$1,998**	**$317**	**$331**	**$30**	**$1,882**	**$905**	**$2,025**	**$9,907**
Less: Oustanding CP	$0	$0	$0	$0	$12	$934	$120	$659	$1,725
Less: PCBs Floaters [2]	$854	$550	$82	$40	$0	$0	$0	$0	$1,527
Net Available Liquidity	**$1,434**	**$1,448**	**$234**	**$291**	**$19**	**$948**	**$785**	**$1,366**	**$6,655**

[1] Consolidated cash balance includes amounts from non-SEC reporting subsidiaries including PowerSecure, Southern Nuclear, SouthernLINC and others
[2] PCB Floaters include all variable rate demand note pollution control revenue bonds outstanding
Source: Southern SEC Filings

Southern and its subsidiaries maintain contracts for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, emissions allowances, and energy price risk management that could require collateral in the event of a ratings downgrade. In the event of an unsecured rating downgrade of certain subsidiaries to Baa3, the maximum collateral requirements would be $647 million as of 30 September 2017. If credit ratings are downgraded to below investment grade, the potential maximum collateral requirement would be $2.4 billion. Generally, collateral could be provided by a Southern guaranty, letter of credit, or cash.

Rating methodology and scorecard factors

Exhibit 7

Rating Factors				
Southern Company (The)				
Regulated Electric and Gas Utilities Industry Grid [1][2]	**Current LTM 9/30/2017**		**Moody's 12-18 Month Forward View As of Date Published [3]**	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Aa	Aa	Aa	Aa
b) Generation and Fuel Diversity	A	A	A	A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	5.3x	A	4x - 5x	A
b) CFO pre-WC / Debt (3 Year Avg)	13.8%	Baa	13% - 15%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	9.6%	Baa	8% - 10%	Baa
d) Debt / Capitalization (3 Year Avg)	52.6%	Baa	52% - 55%	Baa
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	-2	-2	-2	-2
a) Indicated Rating from Grid		Baa2		Baa2
b) Actual Rating Assigned		Baa2		Baa2

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/2017(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics™

Appendix

Exhibit 8

Cash Flow and Credit Measures [1][2]

	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	LTM 09/30/2017
FFO	**$5,401**	**$5,957**	**$5,520**	**$6,039**	**$4,755**	**$6,612**
+/- Other	$574	($83)	($64)	$260	($231)	($335)
CFO Pre-W/C	**$5,975**	**$5,873**	**$5,456**	**$6,299**	**$4,524**	**$6,277**
+/- ΔWC	($744)	$235	$679	($34)	$1,211	$431
CFO	**$5,231**	**$6,109**	**$6,135**	**$6,265**	**$5,735**	**$6,708**
- Div	$1,758	$1,828	$1,926	$1,652	$1,528	$2,062
- Capex	$5,010	$5,606	$6,138	$7,536	$18,237	$18,280
FCF	**($1,537)**	**($1,325)**	**($1,929)**	**($2,922)**	**($14,030)**	**($13,634)**
Total Debt	**$24,403**	**$23,917**	**$26,478**	**$30,644**	**$48,956**	**$51,513**
(CFO Pre-W/C) / Debt	**24.5%**	**24.6%**	**20.6%**	**20.6%**	**9.2%**	**12.2%**
(CFO Pre-W/C - Dividends) / Debt	**17.3%**	**16.9%**	**13.3%**	**15.2%**	**6.1%**	**8.2%**
FFO / Debt	**22.1%**	**24.9%**	**20.8%**	**19.7%**	**9.7%**	**12.8%**
RCF / Debt	**14.9%**	**17.3%**	**13.6%**	**14.3%**	**6.6%**	**8.8%**

[1] All figures & ratios calculated using Moody's estimates & standard adjustments.
[2] 2016 did not reflect a full-year of contributions from Southern Company Gas, as the acquisition closed on 1 July 2016.
Source: Moody's Financial Metrics

Exhibit 9

Peer Comparison Table [1][2]

	Southern Company (The) Baa2 Negative			American Electric Power Company, Inc. Baa1 Stable			Duke Energy Corporation Baa1 Negative			Entergy Corporation Baa2 Negative		
(in US millions)	FYE Dec-15	FYE Dec-16	LTM Sep-17	FYE Dec-15	FYE Dec-16	LTM Sep-17	FYE Dec-15	FYE Dec-16	LTM Sep-17	FYE Dec-15	FYE Dec-16	LTM Sep-17
Revenue	$17,489	$19,896	$22,583	$16,453	$16,380	$15,405	$22,371	$22,743	$23,343	$11,513	$10,846	$11,099
CFO Pre-W/C	$6,299	$4,524	$6,277	$4,714	$4,630	$4,079	$6,833	$6,685	$6,855	$3,395	$3,387	$2,889
Total Debt	$30,644	$48,956	$51,513	$22,071	$23,576	$23,388	$41,536	$49,601	$52,532	$16,892	$18,107	$19,057
(CFO Pre-W/C + Interest) / Interest Expense	7.2x	4.0x	4.5x	5.8x	5.7x	5.2x	5.1x	4.4x	4.4x	5.3x	5.2x	4.8x
(CFO Pre-W/C) / Debt	20.6%	9.2%	12.2%	21.4%	19.6%	17.4%	16.5%	13.5%	13.1%	20.1%	18.7%	15.2%
(CFO Pre-W/C - Dividends) / Debt	15.2%	6.1%	8.2%	16.6%	14.9%	12.5%	11.0%	8.8%	8.4%	16.6%	15.3%	11.9%
Debt / Book Capitalization	47.0%	54.2%	55.5%	42.8%	44.7%	43.4%	44.2%	47.3%	48.0%	49.2%	54.0%	54.2%

[1] [1] All figures & ratios calculated using Moody's estimates & standard adjustments.
Source: Moody's Financial Metrics

Ratings

Exhibit 10

Category	Moody's Rating
SOUTHERN COMPANY (THE)	
Outlook	Negative
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Commercial Paper	P-2
GEORGIA POWER COMPANY	
Outlook	Negative
Issuer Rating	A3
Sr Unsec Bank Credit Facility	A3
Senior Unsecured	A3
Jr Subordinate	Baa1
Pref. Shelf	(P)Baa2
SOUTHERN POWER COMPANY	
Outlook	Stable
Issuer Rating	Baa1
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured	Baa1
Preference Shelf	(P)Baa3
Commercial Paper	P-2
ALABAMA POWER COMPANY	
Outlook	Negative
Issuer Rating	A1
Sr Unsec Bank Credit Facility	A1
Senior Unsecured	A1
Pref. Stock	A3
Commercial Paper	P-1
SOUTHERN COMPANY GAS CAPITAL	
Outlook	Stable
Bkd Senior Unsecured	Baa1
Bkd Commercial Paper	P-2
GULF POWER COMPANY	
Outlook	Stable
Issuer Rating	A2
Senior Unsecured	A2
Pref. Shelf	(P)Baa1
MISSISSIPPI POWER COMPANY	
Outlook	Stable
Corporate Family Rating	Ba1
Senior Unsecured	Ba1/LGD3
Pref. Stock	Ba3/LGD5
Speculative Grade Liquidity	SGL-3
SOUTHERN COMPANY FUNDING CORPORATION	
Outlook	Stable
Commercial Paper	P-2
NORTHERN ILLINOIS GAS COMPANY	
Outlook	Stable
Issuer Rating	A2
First Mortgage Bonds	Aa3
Commercial Paper	P-1
ALABAMA POWER CAPITAL TRUST V	
Outlook	Negative
BACKED Pref. Stock	A2
SOUTHERN ELECT GENERATING CO	

Outlook	Negative
Issuer Rating	A2
Bkd Senior Unsecured	A1

Source: Moody's Investors Service

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CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

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INVESTORS SERVICE

CREDIT OPINION
22 December 2017

Update

Rate this Research

RATINGS

Emera Inc.

Domicile	Nova Scotia, Canada
Long Term Rating	Baa3
Type	LT Issuer Rating - Dom Curr
Outlook	Negative

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Emera Inc.

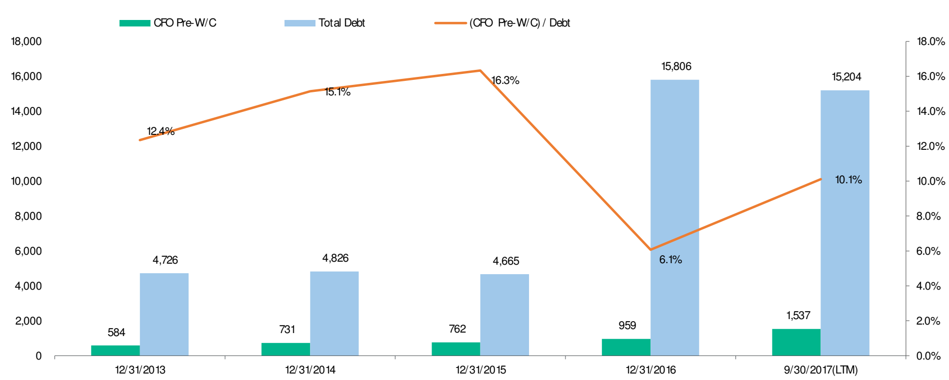
Update following affirmation of Baa3 rating, outlook revised to negative

Summary

Emera Inc.'s (Baa3 negative) credit profile reflects its relatively low risk business profile and geographic and regulatory diversity across its portfolio of operating subsidiaries. Emera's regulated subsidiaries are expected to account for over 90% of consolidated cash flows, a credit positive. However, Emera has a high financial risk profile, evidenced by the significant level of consolidated debt of about CAD15.2 billion at 30 September 2017, resulting in debt to rate base of about 100%. We expect the high leverage will continue to weigh on Emera's consolidated financial metrics and only expect modest improvement in 2018, such that Emera's ratio of cash flow from operations pre-working capital (CFO pre-W/C) to debt will approach 12% in 2018.

Furthermore, Emera's holding company debt as a percentage of total consolidated debt accounts for approximately 50%, which leads to material structural subordination considerations and wider notching differential between the ratings of Emera and its principal operating subsidiaries. For calculation purposes, we include the intermediate holding company debt at TECO Energy (approx. US$1.2 billion as of 30 September 2017) as holding company debt and included the Maritime Link project debt (approx. CAD1.1 billion as of 30 September 2017) financing in consolidated debt.

Exhibit 1
Historical CFO Pre-WC, Total Debt, and CFO Pre-WC to Debt



Source: Moody's Investors Service

Credit Strengths

» Geographically diverse holding company with a portfolio of rate regulated utilities

» High percentage of regulated earnings and cash flow of over 90%

» Largest utility subsidiary, Tampa Electric Company (TEC, A3 stable), accounts for about 50% of cash flow maintains a strong financial profile operating in a highly credit supportive regulatory environment

» Maritime Link construction risk is largely behind them as the transmission line is expected to go into service in 2018

Credit Challenges

» Large amount of holding company debt of about 50% leads to wider notching of ratings for structural subordination and constrains family ratings

» Current financial metrics are weak for rating but are expected to improve in 2018

» Substantial project level debt associated with Maritime Link project is a drag on consolidated metrics but cash flow expected in 2018

» Higher risk non-regulated businesses including gas merchant plants and energy marketing & trading add volatility to cash flow generation

Rating Outlook

Emera's negative rating outlook reflects weaker than expected financial metrics as well as the execution risk associated with improving its financial metrics over the next 12-18 months.

Factors that Could Lead to an Upgrade

A rating upgrade over the near-to-intermediate term is unlikely given the negative outlook and the significant amount of holding company debt at the Emera level. However, the outlook could be revised to stable if Emera were able to improve its financial metrics over the next 12-18 months such that its ratio of CFO pre-W/C to debt was sustained above 12%.

Factors that Could Lead to a Downgrade

Emera's rating could be downgraded if regulatory support of its operating utilities deteriorates; or business risk profile increases through investments in its non-regulated activities; or holding company debt increases further; or if financial metrics do not improve as expected and consolidated CFO pre-W/C to debt remains below 12% on a sustained basis.

Key indicators

Exhibit 2

KEY INDICATORS [1]
Emera Inc.

	12/31/2013	12/31/2014	12/31/2015	12/31/2016	9/30/2017(L)
CFO pre-WC + Interest / Interest	3.7x	4.4x	4.2x	2.8x	3.3x
CFO pre-WC / Debt	12.4%	15.1%	16.3%	6.1%	10.1%
CFO pre-WC – Dividends / Debt	8.2%	10.4%	12.2%	4.2%	7.6%
Debt / Capitalization	60.7%	55.7%	49.6%	63.9%	63.1%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations
Source: Moody's Financial Metrics

Profile

Headquartered in Halifax, Nova Scotia, Emera is a diversified utility and energy services holding company. For the LTM 30 September 2017, Emera reported CAD28 billion in assets and CAD6.3 billion in revenues. Over 90% of Emera's earnings are from rate-regulated businesses. TECO Energy, acquired in July 2016, is Emera's largest subsidiary. TECO Energy is the intermediate parent holding company of Tampa Electric Company and New Mexico Gas Company. Emera also owns Nova Scotia Power Inc., a regulated vertically integrated electric utility that serves approximately 511,000 customers in Nova Scotia, and Emera Maine, a regulated electric T&D utility that serves 157,000 customers in Maine. Emera Caribbean provides electric service to 182,000 customers and has ownership interests in vertically integrated utilities on several Caribbean Islands. Emera also owns gas distribution pipelines in Canada and various generation assets in Canada and New England.

Detailed Credit Considerations

GEOGRAPHICALLY DIVERSE PORTFOLIO OF REGULATED UTILITIES

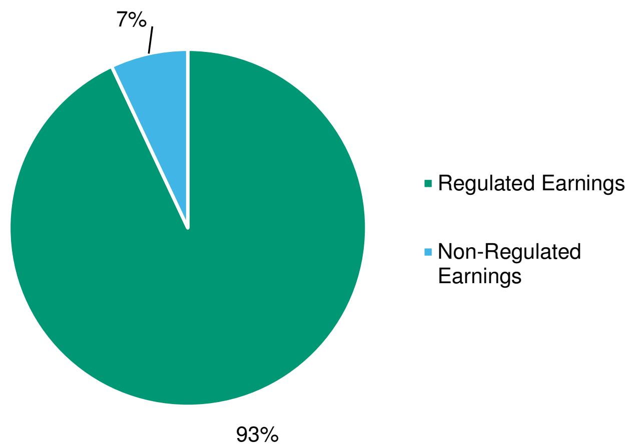
Emera has a geographically and regulatory diverse utility and energy asset operating portfolio in North America. The acquisition of TECO Energy in 2016 substantially increased the percentage of regulated operations in Emera's portfolio, while also further diversifying regulatory exposure with the addition of operations in Florida and New Mexico. Emera's rate regulated utilities account for over 90% of consolidated earnings, which is above Emera's target range of at least 75% regulated earnings. TECO Energy is Emera's largest subsidiary accounting for approximately 50% of consolidated earnings with strong prospects for growth in both Florida and New Mexico. TECO is the intermediate parent holding company of Tampa Electric Company (TEC, A3 stable) and New Mexico Gas Company (NMGC, Not Rated). TEC's electric business, Tampa Electric, provides retail electric service to over 743,000 customers in West Central Florida, while TEC's gas business, Peoples Gas System (PGS), serves over 372,000 customers in Florida's major metropolitan areas. NMGC is a natural gas local distribution company (LDC) serving approximately 523,000 primarily residential customers in New Mexico. Tampa Electric and PGS are regulated by the Florida Public Service Commission (FPSC), while NMGC is regulated by the New Mexico Public Regulation Commission (NMPRC).

Emera's second largest subsidiary is Nova Scotia Power Inc. (NSPI, unrated), a vertically integrated regulated electric utility serving 510,000 customers in the Province of Nova Scotia that accounts for approximately 20% of Emera's earnings. NSPI is allowed an ROE of 8.75% – 9.25% based on a common equity component of 40.0%. NSPI recovers 100% of its fuel costs through a fuel adjustment mechanism and is not subject to an annual general rate review process. NSPI generates stable and predictable cash flows in a generally supportive regulatory jurisdiction with a ratio of cash flow pre-W/C to debt we estimate in the mid-to-high teens range that is similar to mid-Baa rated regulated electric and gas utilities.

Emera's next largest subsidiary is Emera Maine, a low-risk regulated transmission and distribution (T&D) utility that provides services to 157,000 customers in Maine. Emera Maine's transmission assets are regulated under the purview of the Federal Energy Regulatory Commission (FERC), and its distribution services are regulated by the Maine Public Utilities Commission (MPUC). We view the FERC's regulatory framework as above average in credit supportiveness compared to most states. In December 2016, the MPUC issued an order in Emera Maine's rate case authorizing a rate increase of $3.0 million based on an authorized ROE of 9% and a 49% equity ratio. The authorized ROE of 9% included a 50 basis-point penalty imposed by the MPUC for what the regulators are calling management inefficiencies associated particularly around customer service concerns. As a result, we expect management to have a renewed focus on Emera Maine's operations with the intention to strengthen the utility's relationship with state regulators.

Emera also has ownership interests in several Caribbean utilities that serve 182,000 customers collectively including the Barbados Light & Power Co. Ltd. (wholly owned); Emera Caribbean Renewables Limited (wholly owned); 52% interest in Dominica Electricity Services Limited (DOMLEC); and 19.1% interest in St. Lucia Electricity Services Limited. Emera Caribbean also has an 80% ownership interest in the Grand Bahama Power Company. DOMLEC suffered a direct hit from hurricane Maria in September 2017 causing extensive damage to the T&D infrastructure. A restoration plan has not yet been completed. Given that Emera Caribbean accounts for less than 5% of Emera's consolidated earnings, DOMLEC's impact is not material to Emera's financial performance.

Exhibit 3
Over 90% of Emera's earnings and cash flows come from regulated entities



Excludes Corporate & Other
Source: Company's filings

The remaining roughly 5-10% of Emera's earnings is largely derived from non-regulated businesses, including energy marketing and trading operations and merchant generation in the northeast US. A substantial portion of Emera's merchant generation includes gas-fired combined cycle capacity and hydro-electric generation in the New England ISO, which we view as one of the more favorable wholesale energy markets in the US. In 2018, Emera is expected to benefit from increased capacity payments from $7.03/kw-month to $9.55/kw-month scheduled to take effect in June 2018. This could result in increased cash flow of almost CAD50 million next year. However, as a whole, Emera's unregulated businesses have a substantially higher risk profile than Emera's regulated subsidiaries given the lower predictability and volatility of earnings and cash flow, which ultimately weighs on the credit profile of Emera's diversified portfolio.

OWNERSHIP OF TECO ENERGY BOLSTERS BUSINESS RISK PROFILE AND CASH FLOWS

TECO Energy accounts for about 50% of Emera's consolidated earnings and cash flows and strengthens Emera's business risk profile and portfolio diversity. Furthermore, we view the Florida regulatory environment very credit supportive when compared to most state jurisdictions. Emera completed its acquisition of TECO Energy on 1 July 2016, for an aggregate purchase price of approximately $10.4 billion, including the assumption of approximately $4.1 billion of debt. The large amount of debt used to finance the transaction has significantly decreased Emera's financial flexibility and weigh on consolidated metrics. As a result of the acquisition, Emera's consolidated earnings have increased the percentage of regulated earnings from about 70% pre-merger to over 90%.

TEC and PGS are allowed credit supportive returns and are able to utilize a broad group of credit supportive cost recovery mechanisms. TEC's last general rate case settlement order by the Florida Public Service Commission (FPSC) in September 2013 provided a high degree of rate certainty through the end of 2017. The settlement included a multi-step rate increase including an initial $57.5 million rate increase in November 2013, $7.5 million in November 2014 and $5 million in November 2015. On 6 November 2017, the FPSC approved an amended and restated settlement agreement that replaced the 2013 settlement agreement.

TEC's authorized ROE range is 9.25 – 11.25% with a mid-point ROE of 10.25% based on an equity ratio of 54%. The authorized ROE could increase to 11.5% depending on the movement of the average 30-year US Treasury Bond yield rate for any period of six consecutive months. Under the revised settlement agreement, TEC can not file for new base rates to be effective until 1 January 2022 unless TEC's earned ROE falls below the bottom of the authorized range.

The 2013 settlement agreement included certainty on the recovery of costs associated with the Polk Units 2-5 combined-cycle plant conversion project including the $110 million rate base increase that went into effect in mid-January 2017 when the conversion project was completed and the Polk plant went into service. TEC also benefits from several other credit supportive regulatory mechanisms, including fuel and purchased power recovery clauses, which are adjusted annually based on expected fuel and purchased power prices, and for prior period differences between projected and actual costs. TEC has an environmental cost recovery clause that is adjusted annually for capital spending and operating expenses related to environmental compliance.

In addition, the revised settlement agreement included a Solar Base Rate Adjustment (SoBRA) mechanism, which will allow TEC to begin recovering its solar investments immediately upon completion of the solar projects. The SoBRA projects will earn a return based on an allowed ROE of 10.25% and an equity ratio of 54%. We believe the regulatory mechanisms are credit supportive as they improve the timeliness of cost recovery and help maintain stable and predictable cash flow generation.

PGS' last rate case order was in 2009. However, as part of a settlement adopted by the FPSC in February 2017, PGS will not file a base rate case before 31 December 2020, unless the utility's earned ROE falls below 9.25%. As a result of the recent settlement, PGS' authorized ROE range slightly widened from 9.25% to 11.75% over the term of the settlement with a midpoint ROE of 10.75%. PGS' equity ratio is 54.7%. PGS utilizes a purchased gas adjustment (PGA) clause that is designed to recover purchased gas costs in a timely manner as well as a Cast Iron/Bare Steel Pipe Replacement Rider, which enables PGS to recover, through an annual customer surcharge, the costs associated with accelerating the replacement of cast iron, bare steel distribution pipes and "problematic plastic pipe" on its system over a 10-year period beginning January 2013.

We view the New Mexico regulatory environment as generally less constructive than most states. With that said, NMGC is not a material earnings driver of TECO and is an even smaller part of Emera. NMGC's last rate case in 2012 resulted in a $22.1 million rate increase that same year based on a 10% implied ROE and a 52% equity ratio. NMGC utilizes an automatic purchase gas adjustment clause for timely recovery of fuel charges. In addition, the financing costs associated with hedging activities used by NMGC to mitigate the impact of cost spikes in natural gas are recovered through the purchased gas adjustment clause. NMGC is not required to file a rate case by a pre-determined date. Further, in 2013 the NMPRC had adopted a future test year for ratemaking, which we view as a constructive means to reduce regulatory lag and ensure timely recovery of costs and investments.

SIGNIFICANT AMOUNT OF HOLDING COMPANY DEBT LEADS TO WIDER NOTCHING AND CONSTRAINS FAMILY RATINGS

Emera issued a significant amount of debt and subordinated hybrid notes to finance its acquisition of TECO Energy. As a result, Emera's holding company debt is approximately 50% of consolidated debt. For calculation purposes, we include the intermediate holding company debt at TECO Energy (approx. US$1.2 billion as of 30 September 2017) as holding company debt and included the Maritime Link project debt (approx. CAD1.1 billion as of 30 September 2017) financing in consolidated debt. This high level of holding company debt leads to a wider notching differential between Emera's rating and that of its principal subsidiaries. We do not see a transparent means for Emera to organically de-lever in a material way over the near-to-intermediate term, which we view as a credit negative because Emera will have limited financial flexibility to address unexpected challenges.

On 6 December 2017, Emera announced an agreement to initially sell 14.6 million shares at CAD47.90 each for gross proceeds of about CAD700 million. Gross proceeds may increase by an additional CAD50 million should underwriters exercise an overallotment option to purchase an additional 1,045,000 shares. The equity issuance is credit positive because it strengthens Emera's liquidity and supports the company's effort to improve its financial metrics. The net proceeds will be used to reduce holding company debt and help fund future investments.

No specific ring-fence type provisions at TEC exist to insulate TEC's credit profile from the high debt levels at its immediate holding company parent, TECO Energy (via its financing arm, TECO Finance), but also the high leverage at Emera. As a result, the significant level of debt at the parent constrains the ratings of TECO Energy and TEC.

MARITIME LINK PROJECT IS EXPECTED TO GENERATE CASH FLOW WHEN PLACED INTO SERVICE IN 2018

Emera is in the final year of the construction phase of the 500 MW Maritime Link Transmission Project, a 170km transmission line in northeast Canada, that will be owned and operated by NSP Maritime Link Inc., an affiliated company to NSP. The transmission line is being built to bring renewable (principally hydro) energy to Nova Scotia, and other areas. The project began construction in 2014 and is expected to go into service in January 2018. The CAD1.6 billion regulated transmission line is allowed an ROE of 8.75 – 9.25% and an equity ratio of 30%. As of 30 September, 2017, Emera has invested approximately CAD1.5 billion into the project, of which about 30% is equity and the remainder is working capital and debt, which is guaranteed by the Government of Canada. Emera's investments into the project are being funded through the parent holding company.

To date, management has stated the project remains on schedule and within budget and is expected to be fully operational by the end of 2017. The principal supplier of the hydro generation is the 824 MW Muskrat Falls hydroelectric facility being constructed by Nalcor Energy (unrated), who also owns the project. Nalcor is 100% owned by the Province of Newfoundland & Labrador (Aa3, negative). The Muskrat Falls project has fallen behind schedule, is over budget, and is now expected to be completed by late 2020, at the earliest. For analytical purposes, we include the Maritime Link project debt in Emera's consolidated financial metrics, which will result in a near-to-intermediate term drag given that the transmission line is not expected generate cash flow until 2018. As a result of a regulatory decision in June 2017, Nova Scotia Power had to defer collecting depreciation costs from ratepayers in 2018 and 2019 so the savings can be returned to customers in annual credits. As a result, Maritime Link's cash flow generation will be lower in 2018 and 2019 by about CAD50 million each year.

FINANCIAL METRICS ARE WEAK FOR RATING WITH MODEST IMPROVEMENT EXPECTED

For the twelve months ended 30 September 2017, Emera's ratio of cash flow from operations pre-working capital (CFO pre-W/C) to debt was approximately 10% which is lower than the 11% we expected in 2017. In 2017, Emera's financial metrics were impacted by substantially weaker results at its unregulated energy marketing & trading business, Energy Services. When we initially assigned the Baa3 rating last year, we incorporated a view that Emera's financial profile would gradually improve over time, such that Emera's ratio of CFO pre-W/C to debt will steadily increase to about 14% in 2019 from around 11% in 2017.

Over the next 12-18 months, we expect Emera will continue to exhibit financial policies that emphasize holding company debt reduction and improving cash flow generation across its portfolio of subsidiaries. Our negative outlook will focus on the company's execution to improve its financial metrics. We could change the outlook back to stable if Emera is able to improve its ratio of CFO pre-W/C to debt to above 12% by the end of 2018. At the same time, Emera's rating could be downgraded if financial metrics do not improve as we expect and Emera's ratio of CFO pre-W/C to debt remains below 12% on a sustained basis.

Liquidity Analysis

Emera has an adequate liquidity profile driven by upstream dividends from its diverse and largely regulated portfolio of utilities and sufficient external availability.

Emera's external sources of liquidity include revolving credit facilities at the parent and several of its subsidiaries. Emera maintains a CAD700 million senior unsecured revolving credit facility that expires June 2020, which had CAD419 million available as of September 30, 2017. NSP has a CAD600 million senior unsecured revolving credit facility that expires in October 2021, which had CAD342 million available at September 30, 2017. Emera Maine also has its own $80 million senior unsecured revolving credit facility that expires September 2019, which had $52 million of availability at September 30, 2017. Emera's revolving credit facility has only one maintenance financial covenant of maximum debt to capitalization of 70%. At December 31, 2016, Emera's consolidated debt to capitalization was 63%.

TECO Energy, TEC and NMGC also have their own separate revolving credit facilities. TECO Energy has a $300 million senior unsecured revolving credit facility expiring in March 2022. TEC has a $325 million bank credit facility expiring in March 2022 and a $150 million accounts receivable collateralized borrowing facility that expires in March 2018. In November 2017, TEC entered into a $300 million term loan that matures in November 2018. NMGC has a $125 million bank credit facility expiring March 2022. Please refer to TECO Energy and TEC's respective credit opinions for further discussion of their respective liquidity analysis.

Over the 12-month period ending 30 September 2017, Emera generated approximately CAD1.3 billion in cash flow from operations, invested about CAD1.5 billion in capital investments and made CAD388 million in dividend distributions resulting in negative free cash flow of about CAD560 million. Emera used asset sales, equity issuances and short-term borrowings to supplement the shortfall in cash flow. Going forward, we expect Emera's cash flow from operations will approximately cover planned capital expenditures. Emera's next significant near-term debt maturity is $225 million of medium-term notes due in 2019.

Structural Considerations

The Ba2 rating assigned to the subordinated hybrid notes is two notches below Emera's Baa3 senior unsecured rating as they are subordinated to substantially all of the company's other debt obligations. The notes have a long-dated maturity (60 years) and Emera can opt to defer coupons on a cumulative basis for up to five years. For further details, please refer to Moody's Cross Sector Rating Methodology "Hybrid Equity Credit" (January 2017).

Rating Methodology and Scorecard Factors

Exhibit 4

Rating Factors		
Emera Inc.		
Regulated Electric and Gas Utilities Industry Grid [1][2]	**Moody's 12-18 Month Forward View As of Date Published [3]**	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A
b) Consistency and Predictability of Regulation	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)		
a) Timeliness of Recovery of Operating and Capital Costs	A	A
b) Sufficiency of Rates and Returns	Baa	Baa
Factor 3 : Diversification (10%)		
a) Market Position	Aa	Aa
b) Generation and Fuel Diversity	Baa	Baa
Factor 4 : Financial Strength (40%)		
a) CFO pre-WC + Interest / Interest (3 Year Avg)	3.3x - 3.8x	Baa
b) CFO pre-WC / Debt (3 Year Avg)	9% - 13%	Ba
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	7% - 11%	Baa
d) Debt / Capitalization (3 Year Avg)	56% - 61%	Ba
Rating:		
Grid-Indicated Rating Before Notching Adjustment		Baa1
HoldCo Structural Subordination Notching	-2	-2
a) Indicated Rating from Grid		Baa3
b) Actual Rating Assigned		Baa3

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/17 (LTM)
[3]This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Investors Service

Ratings

Exhibit 5

Category	Moody's Rating
EMERA INC.	
Outlook	Negative
Issuer Rating -Dom Curr	Baa3
Senior Unsecured -Dom Curr	Baa3
Subordinate	Ba2
EMERA US FINANCE LP	
Outlook	Negative
Bkd Senior Unsecured	Baa3
TAMPA ELECTRIC COMPANY	
Outlook	Stable
Issuer Rating	A3
Sr Unsec Bank Credit Facility	A3
Senior Unsecured	A3
TECO FINANCE, INC.	
Outlook	Stable
Bkd Senior Unsecured	Baa2
TECO ENERGY, INC.	
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured Shelf	(P)Baa2

Source: Moody's Investors Service

REPORT NUMBER 1103313

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

MOODY'S
INVESTORS SERVICE

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
22 December 2017

Update

Rate this Research

Enbridge Inc.

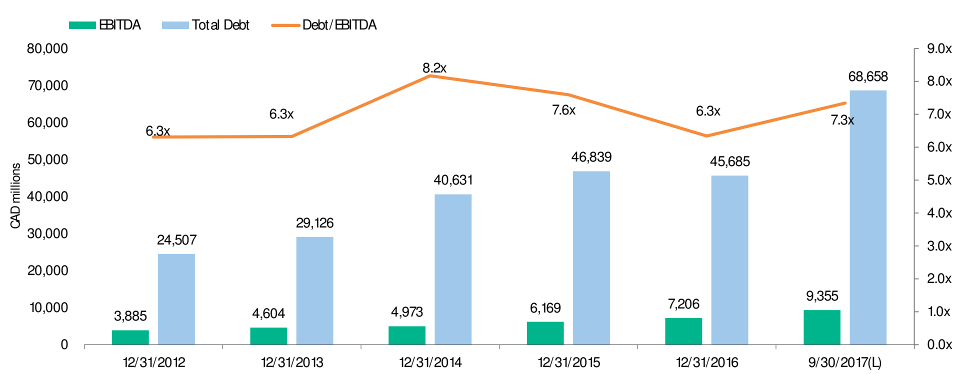
Update following downgrade to Baa3 outlook changed to stable.

Summary

Enbridge Inc's (ENB) credit profile reflects the company's large size and scale and its diverse, low risk asset base offset by high leverage and structural subordination. We expect its portfolio of assets will continue to generate stable cash flow based on a combination of rate regulation, a favorable contractual profile and a strong competitive position. ENB's low-risk business position is supported by its ownership of an extensive, growing crude oil and gas network on which North America relies. The company continues to move forward with its large capital program which highlights ongoing execution risk. The company's track record for executing its capital programs on time and within budget is faltering on its largest, most high profile projects.

The company has weak financial metrics that are expected to improve in the near term as a result of recently announced management actions, projects entering in service and beginning to generate cash flow. Financial metrics are currently weak in relation to the levels we associate with the current rating however we expect them to improve in the near term. Debt to EBITDA in the table below overstates leverage because it includes almost all of the Moody's adjusted debt associated with the acquisition of Spectra Energy Corp (Baa2 stable) and only 7 months of earnings. On an annualized basis we calculate debt to EBITDA of about 6.4x. The ratings also reflect the structural subordination of ENB creditors, financial policies that often favor shareholders and a complex organizational and capital structure.

Exhibit 1
Historical EBITDA, Total Debt and Debt to EBITDA



Source: Moody's Financial Metrics, the figures in the exhibit above have not been annualized for the Feb 27 2017 acquisition of Spectra Energy Corp.

RATINGS

Enbridge Inc.

Domicile	Alberta, Canada
Long Term Rating	Baa3
Type	LT Issuer Rating
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Credit Strengths

» Large size and diversification benefits

» Low business risk and predictable cash flow

» Enhanced market position following Spectra combination

Credit Challenges

» High leverage

» Sizeable multiyear capital program with execution risk

» Structural subordination and organizational complexity

Rating Outlook

ENB's stable outlook reflects its predictable cash flow improving financial metrics.

Factors that Could Lead to an Upgrade

» Moody's adjusted debt to EBITDA is sustained comfortably below 5.5x.

» A large reduction in its organizational complexity and structural subordination

Factors that Could Lead to a Downgrade

» Moody's adjusted debt to EBITDA is sustained well above 6x.

» Increases in structural subordination, more aggressive financial policies or a material change in the company's business risk could also lead to a downgrade.

Key Indicators

Exhibit 2

KEY INDICATORS [1]

Enbridge Inc.

	12/31/2013	12/31/2014	12/31/2015	12/31/2016	9/30/2017(L)
Net Property Plant and Equipment (USD Million)	$40,017.9	$46,901.8	$46,734.4	$48,079.9	$77,158.7
EBITDA (USD Million)	$4,470.0	$4,505.1	$4,833.6	$5,441.2	$7,126.0
EBITDA / Interest Expense	3.5x	2.9x	2.9x	3.5x	3.8x
Debt / EBITDA	6.3x	8.2x	7.6x	6.3x	7.3x
(FFO - Maintenance CAPEX) / Distributions	2.1x	1.9x	2.1x	2.0x	1.5x

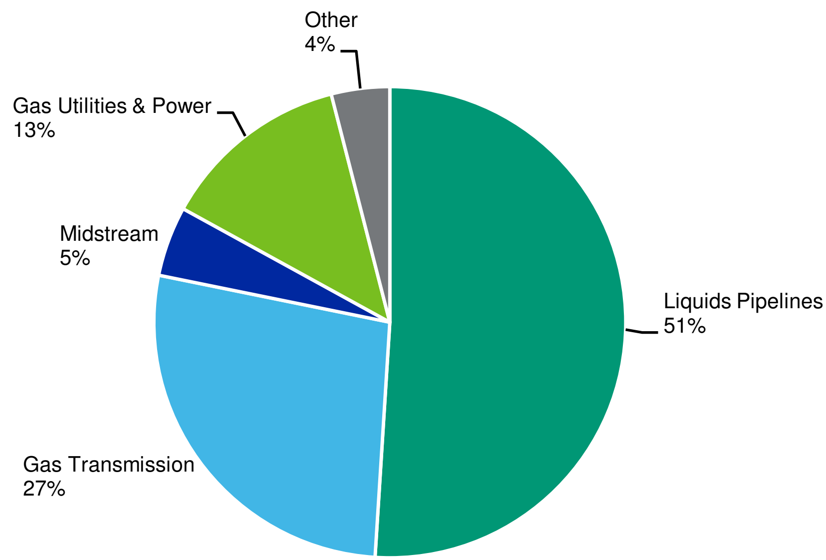
[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Profile

ENB is a North American energy delivery company. Following the Spectra acquisition the company has more than 18,000 miles of liquids pipelines and 200,000 miles of natural gas and natural gas liquids pipelines. ENB has five operating segments: Liquids Pipelines (53% of 2016 adjusted earnings before interest, income taxes and depreciation and amortization(EBITDA)), Gas Pipelines and Processing (31%), Gas Distribution (13%), and Green Power, Transmission and Energy Services (3%). This approach combines the operating segment EBITDA for Enbridge Inc. and Spectra Energy Corp. on a consolidated basis.

ENB does some of its investing and financing through its partially owned subsidiaries, which ENB controls as the General Partner sponsor with partial economic interests. In the US, ENB has a master limited partnership (MLP), EEP (Baa3 stable, 34.7% interest as of 30 September 2017), and in Canada, it has EIF (Baa3 negative, 84.6% interest as of 30 September 2017). ENB also owns 100% of Spectra Energy Corp's shares, whose key asset is its MLP, Spectra Energy Partners, of which it owns 75%. ENB also has debt financing in its gas distribution business and some project level debt. Enbridge's gas distribution businesses are carried out primarily by wholly owned subsidiaries Enbridge Gas Distribution Inc (not rated) and Union Gas Limited (not rated).

Exhibit 3
2018 forecast EBITDA by segment



Source: Company

Detailed Credit Considerations

LARGE SIZE, SCALE AND DIVERSIFICATION BENEFITS

ENB continues to benefit from substantial financial resources, with combined (ENB and Spectra) EBITDA of about C$11 billion over the latest twelve months ended September 30th 2017 (inclusive of a full year of earnings from Spectra Energy Corp) and combined net PP&E of about C$96 billion. Economies of scale from its large asset base of more than C$134 billion and strong market access all support current credit quality. The company's credit quality benefits from extensive diversification, and the performance of some of its assets have low levels of correlation.

LOW BUSINESS RISK AND PREDICTABLE CASH FLOW

ENB's low business risk continues to be a key credit strength and rating driver. The vast majority of ENB's earnings and cash flow comes from businesses that benefit from either rate regulation, long term contracts that often have credit-positive take or pay provisions, a strong competitive position, or a combination of some or all of the above. In aggregate we expect that about 95% of the company's EBITDA will be generated by cost of service, take or pay contracts, or earnings under the CTS (competitive tolling settlement), providing long term, stable earnings. The vast majority of the company's counterparties are investment grade, lending strength to the predictability of cash flow.

The combination with Spectra has had a positive impact on the business mix, from one that had been dominated by liquids pipelines to a more even split between liquids and the gas businesses anchored by interstate pipelines and gas distribution businesses, and to a lessor extent, gas processing.

The lowest risk businesses are the regulated monopoly gas distribution businesses followed by the liquid and gas pipeline businesses, which are underpinned by strong fundamentals. The renewables business has a somewhat weaker business risk profile because long term contracts continue to expose the company to resources risk. The midstream segment, formerly called gas processing, has some stable underlying contracts, however there are also riskier elements within this segment although the segment itself is quite small. The weakest segment of the business is Energy Services, which typically has a small impact on the company's performance.

SIZEABLE, MULTIYEAR CAPITAL PROGRAM

The company continues to progress with its large capital program however execution remains elevated. The company's capital program consists of about C$32 billion of capital projects that are expected to go into service between 2017 and 2019.

Once in service the combined C$32 billion capital program will result in more assets with a strong business risk profile, maintaining the strength of the company's business risk over time.

The company has generally had a strong track record of executing its capital program on time and budget. However the company has not been immune to a powerful sector trend of increasing execution risks, particularly for large, high profile projects. The announced delays to the in-service of the roughly C$9 billion (initially about C$8.2 billion) L3R is part of a broader sector trend. Despite several positive elements from an execution perspective, the L3R project, the most expensive single project in the company's history, has not been immune. For example, the L3R did not require a presidential permit or amendment, it largely utilized existing rights of way, it capitalized on Enbridge's lengthy track record of dealing with the relevant regulatory frameworks and authorities and incorporated an extensive period of consultation to address various stakeholder concerns. Nonetheless managements expected in-service has been delayed twice from initially late 2017 to late 2019. The L3R differs from some of Enbridge's other projects where contractual features result in cost overruns being rolled into tolls once a project is in service. While there are no penalties to Enbridge for delays in bringing the project in service, cash flow does not commence until the project is completed.

With the exception of the L3R the company's capital program consists of many smaller projects that generally carry less execution risk, but are not immune to it, for example the USD1.3 billion Nexus project. Management has also identified tens of billions of dollars projects that it expects to progress primarily post-2020. Generally we expect that the capital program will be focused on low business risk projects and not drive a fundamental change in the business risk profile of the company. The company has identified C$10 billion of non-core assets it could sell, which typically have a weaker business risk on average compared to the rest of the company. These assets sales are unlikely to change our fundamental opinion of the compan's business risk profile.

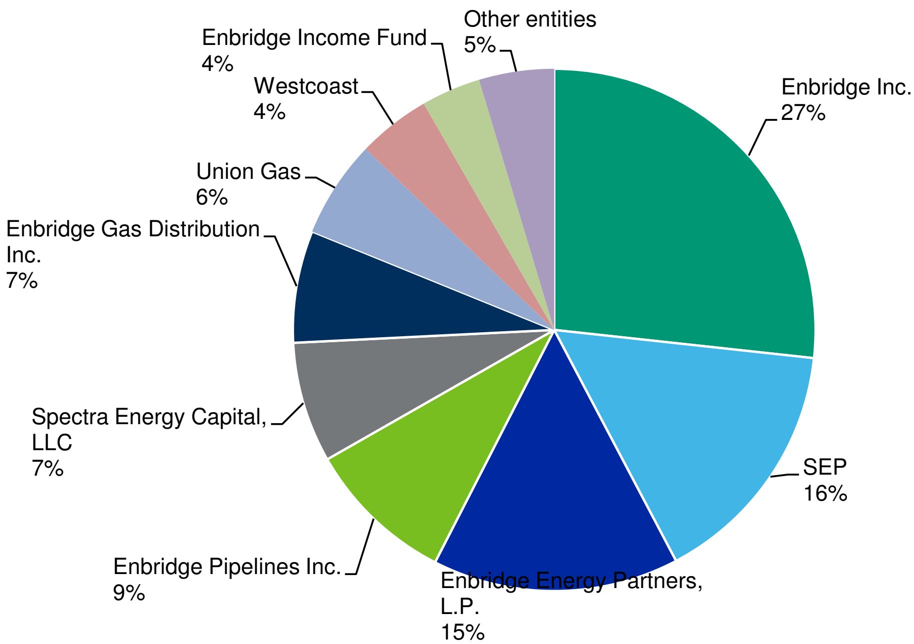
WEAK FINANCIAL METRICS AND STRUCTURAL SUBORDINATION

The large, ongoing capital program and leveraged financial structure continues to put pressure on the company's financial metrics. Over the twelve months ended September 30, 2017 we calculate debt to EBITDA of about 6.4x. Prior to the combination with Spectra and delays to the L3R we expected debt/EBITDA below 5.5x with the in-service of the L3R project at the end of 2017.

EBITDA growth will be driven by the in service of about C$12 billion of capital projects in 2017. Capital-in-service declines in 2018 to C $7 billion before rebounding to C$13 billion in 2019, highlighting the size of the L3R relative to the company's capital program. While the C$12 billion of projects in-service in 2017 is substantial, in the context of the company's C$96 billion of PP&E at Q3 2017, it is less so, limiting the improvement in consolidated financial metrics. The company has forecast incremental capital spending of C$9 billion in 2018 and C$8 billion in 2019, inclusive of maintenance capital. In addition to utilizing existing cash flow from operations, management has many levers to pull in an effort to finance the capital program and delever financial metrics. In addition to a recent C$2 billion equity raise, management has committed to C$3 billion of asset sales and an additional C$3.5 billion of hybrid equity in 2018. Management has also identified a total of C$10 billion of non-core assets that it could sell (a figure that includes the C$3 billion it plans to sell in 2018) to manage pressure on its balance sheet and has indicated it could issue equity at various levels throughout the group. Taken together these actions should lead to a material improvement in financial metrics. Management is also targeting incremental synergies stemming from the Spectra acquisition by the end of 2019.

Structural subordination and increasing distributions are clear signals of a set of financial policies that often favor shareholders at the expense of creditors, a credit negative. High levels of structural subordination and very high levels of complexity are not uncommon at Enbridge. The substantial growth in partially owned sponsored investments that are fully consolidated and have distributions to non-controlling interests equal to roughly 10% of EBITDA and the likelihood of fluctuating ownership interests over time are key drivers of analyzing the company using a proportionate consolidation approach to ENB's financial analysis in addition to our consolidated approach that we continue to base our analysis on.

Exhibit 4
2016 total reported pro-forma debt by entity



Source: Company

Liquidity Analysis

The company has substantial external liquidity arrangements and its liquidity is considered adequate so long as it is able to continue to renew its expiring 364-day facilities and refinance its upcoming debt maturities. ENB's ongoing strong access to the capital markets significantly mitigates liquidity risk.

ENB had about $24.1 billion of committed liquidity resources at the holding company, some of its fully owned and partially owned subsidiaries as of September 30, 2017. ENB's key facilities include a C$2.475 billion five-year revolving term facility expiring in 2022, a US$1.3 billion three-year revolving term facility expiring in 2020 as well as a US$2 billion five-year term revolver expiring in 2022 at EEP and US$2.5 billion long-term revolver expiring in 2021-22 at SEP. Besides EIF's C$1,500 million three-year revolving term facility, Westcoast's and Union Gas's long-term credit facilities of total amount of C$1,100 million, the majority of the rest are 364-day facilities. ENB extended the maturities on the majority of these facilities for another year in 2017. These 364-day facilities have one-year term-out options.

The credit agreements have financial covenants including one setting the maximum debt to total consolidated capitalization (as defined in the credit agreement) to 75%. As of September 30, 2017, ENB was in compliance with all of its covenants and we expect ENB to remain in compliance.

As of September 30, 2017, ENB had $0.7 billion of unrestricted cash on hand and $10.3 billion of available borrowing capacity across its bank facilities, covering about one year of forward funding requirements. For the year ended September 30, 2017, ENB generated around $6 billion of cash from operations, spent $7.4 billion in capital expenditures, and paid $3.3 billion in dividends (including minority interests) resulting in approximately $4.8 billion of negative free cash flow (all numbers are Moody's adjusted).

Rating Methodology and Scorecard Factors

Exhibit 5
Rating FactorsEnbridge Inc.

Energy, Oil & Gas - Midstream [MLP] Industry Grid [1][2]	Current LTM 9/30/2017		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Scale (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Net Property Plant and Equipment (USD Million)	$77,158.7	Aaa	$85,000 - $95,000	Aaa
b) EBITDA (USD Million)	$7,126.0	Aa	$8,500 - $10,100	Aaa
Factor 2 : Business Profile (25%)				
a) Estimated Price & Volume Risk Exposure	A	A	A	A
Factor 3 : Financial Leverage & Distribution Profile (40%)				
a) EBITDA / Interest Expense	3.8x	Ba	3.5x - 4x	Ba
b) Debt / EBITDA	7.3x	Caa	5.3x - 5.6x	Ba
c) (FFO - Maintenance CAPEX) / Distributions	1.5x	Baa	1.6x - 1.9x	Baa
Factor 4 : Financial Policy (10%)				
a) Financial Policy	Ba	Ba	Ba	Ba
Rating:				
a) Indicated Outcome from Scorecard		Baa2		Baa1
b) Actual Rating Assigned				Baa3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] s of 9/30/2017(L).
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics™

APPENDIX

Exhibit 6
Peer Comparison Table

	Enbridge Inc. Baa3 Stable			TransCanada Corporation Baa1 Stable			Kinder Morgan Inc. Baa3 Stable		
(in US millions)	FYE Dec-15	FYE Dec-16	LTM Sep-17	FYE Dec-15	FYE Dec-16	LTM Sep-17	FYE Dec-15	FYE Dec-16	LTM Sep-17
Revenue	$27,482	$26,118	$30,720	$8,854	$9,442	$10,260	$14,403	$13,058	$13,462
EBITDA	$4,834	$5,441	$7,126	$4,740	$5,391	$6,087	$7,569	$6,988	$6,994
Net PP&E	$46,734	$48,080	$77,159	$32,866	$41,154	$45,222	$41,185	$39,319	$40,481
Total Debt	$33,719	$34,066	$54,898	$26,478	$34,565	$34,810	$42,854	$40,286	$38,610
Cash & Cash Equiv.	$731	$1,579	$596	$612	$758	$1,139	$229	$684	$539
EBITDA / Int. Exp.	2.9x	3.5x	3.8x	3.6x	3.3x	3.5x	3.6x	3.8x	3.7x
Debt / EBITDA	7.6x	6.3x	7.3x	6.1x	6.5x	5.4x	5.7x	5.8x	5.5x
RCF / Net Debt	6.2%	6.6%	4.1%	7.6%	6.5%	8.7%	1.6%	9.3%	9.2%
FFO-Maint. CAPEX/Distrib.	2.1x	2.0x	1.5x	2.0x	2.0x	2.3x	1.0x	3.4x	3.2x

All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade. ENB figures in the table above have not been annualized for the Feb 27 2017 Spectra Energy Corp acquisition.
Source: Moody's Financial Metrics™.

Exhibit 7

Enbridge Inc. Moody's-Adjusted Debt Breakdown

(in CN$ Millions)	FYE Dec-12	FYE Dec-13	FYE Dec-14	FYE Dec-15	FYE Dec-16	LTM Ending Sep-17
As Reported Debt	**21,917.0**	**25,880.0**	**35,975.0**	**42,341.0**	**41,568.0**	**65,665.0**
Pensions	379.0	110.0	413.0	328.0	403.0	403.0
Operating Leases	282.3	490.0	910.0	837.7	514.6	514.6
Hybrid Securities	1,928.5	2,645.5	3,332.5	3,332.5	3,199.0	2,075.0
Moody's-Adjusted Debt	**24,506.8**	**29,125.5**	**40,630.5**	**46,839.2**	**45,684.6**	**68,657.6**

All figures are calculated using Moody's estimates and standard adjustments.
Pensions and operating leases adjustments are not inclusive of Spectra Energy Corp.
Source: Moody's Financial Metrics™.

Exhibit 8

Enbridge Inc. Moody's-Adjusted EBITDA Breakdown

(in CN$ Millions)	FYE Dec-12	FYE Dec-13	FYE Dec-14	FYE Dec-15	FYE Dec-16	LTM Ending Sep-17
As Reported EBITDA	**3,263.0**	**2,930.0**	**4,879.0**	**3,659.0**	**6,281.0**	**9,902.0**
Pensions	34.0	29.0	-2.0	5.0	-24.0	-24.0
Operating Leases	31.0	49.0	91.0	0.0	0.0	0.0
Unusual	557.0	1,596.0	5.0	2,505.0	949.0	-523.0
Moody's-Adjusted EBITDA	**3,885.0**	**4,604.0**	**4,973.0**	**6,169.0**	**7,206.0**	**9,355.0**

All figures are calculated using Moody's estimates and standard adjustments.
Pensions and operating leases adjustments don't include Spectra's numbers. ENB EBITDA has not been annualized for the Feb 27 2017 Spectra Energy Corp acquisition.
Source: Moody's Financial Metrics™.

Exhibit 9

Enbridge Inc.

Selected Historic Moody's Adjusted Financial Data

CAD (Million)	FYE Dec-13	FYE Dec-14	FYE Dec-15	FYE Dec-16	LTM Ending Sep-17
INCOME STATEMENT					
Revenue	33,645.0	37,396.0	35,075.0	34,589.0	40,329.0
EBITDA	4,604.0	4,973.0	6,169.0	7,206.0	9,355.0
EBIT	3,204.2	3,335.3	4,145.0	4,966.0	6,403.0
Interest expense	1,319.1	1,707.1	2,135.1	2,039.8	2,477.0
BALANCE SHEET					
Cash & Cash Equivalents	756.0	1,261.0	1,015.0	2,117.0	745.0
Total Debt	29,125.5	40,630.5	46,839.2	45,684.6	68,657.6
Total Liabilities	47,057.3	60,096.6	69,593.7	67,974.5	108,332.5
CASH FLOW					
Capital Expenditures (CAPEX)	8,226.8	10,376.7	7,021.0	4,934.0	7,429.0
Cash from Investing Activities	(9,210.8)	(11,535.7)	(7,580.0)	(4,871.0)	(7,734.0)
Dividends	1,300.5	1,482.5	1,888.0	2,248.7	3,303.1
Retained Cash Flow (RCF)	2,148.8	2,282.7	2,831.0	2,883.0	2,758.0
RCF / Debt	7.4%	5.6%	6.0%	6.3%	4.0%
Free Cash Flow (FCF)	(6,446.0)	(9,763.0)	(4,835.0)	(2,409.0)	(4,777.0)
FCF / Debt	-22.1%	-24.0%	-10.3%	-5.3%	-7.0%
PROFITABILITY					
% Change in Sales (YoY)	33.6%	11.1%	-6.2%	-1.4%	19.3%
EBIT Margin %	9.5%	8.9%	11.8%	14.4%	15.9%
EBITA Margin %	9.8%	9.2%	12.3%	14.9%	16.3%
EBITDA Margin %	13.7%	13.3%	17.6%	20.8%	23.2%
INTEREST COVERAGE					
EBIT / Interest Expense	2.4x	2.0x	1.9x	2.4x	2.6x
EBITDA / Interest Expense	3.5x	2.9x	2.9x	3.5x	3.8x
(EBITDA - CAPEX) / Interest Expense	-2.7x	-3.2x	-0.4x	1.1x	0.8x
LEVERAGE					
Debt / EBITDA	6.3x	8.2x	7.6x	6.3x	7.3x
Net Debt/EBITDA	6.2x	7.9x	7.4x	6.0x	7.3x
Debt / (EBITDA - CAPEX)	-8.0x	-7.5x	-55.0x	20.1x	35.6x
Avg.Assets / Avg.Equity	5.5x	5.5x	5.5x	5.1x	3.5x

All figures are calculated using Moody's estimates and standard adjustments. Figures have not been annulized to reflect the Feb 27 acquisition of Spectra Energy Corp.
Source: Moody's Financial Metrics™.

Ratings

Exhibit 10

Category	Moody's Rating
ENBRIDGE INC.	
Outlook	Stable
Issuer Rating	Baa3
Senior Unsecured	Baa3
Subordinate	Ba2
Pref. Stock -Dom Curr	(P)Ba2
ENBRIDGE ENERGY PARTNERS, L.P.	

Outlook	Stable
Issuer Rating	Baa3
Senior Unsecured	Baa3
Jr Subordinate	Ba1
Commercial Paper	P-3
SPECTRA ENERGY PARTNERS, LP	
Outlook	Stable
Senior Unsecured	Baa2
Commercial Paper	P-2
ENBRIDGE INCOME FUND	
Outlook	Negative
Senior Unsecured -Dom Curr	Baa3
SPECTRA ENERGY CAPITAL, LLC	
Outlook	Stable
Bkd Senior Unsecured	Baa2
TEXAS EASTERN TRANSMISSION L.P.	
Outlook	Stable
Senior Unsecured	Baa1
ENBRIDGE ENERGY LIMITED PARTNERSHIP	
Outlook	Stable
Senior Unsecured	Baa2
Subordinate Shelf	(P)Baa3
EXPRESS PIPELINE LIMITED PARTNERSHIP	
Outlook	Stable
Bkd Senior Secured	Baa1
Bkd Subordinate	Baa3
ENBRIDGE (U.S.) INC.	
Outlook	No Outlook
Bkd Commercial Paper	P-3

Source: Moody's Investors Service

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CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454